FILED
October 30, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

TESTIMONY OF

LANE KOLLEN – PUBLIC'S EXHIBIT NO. 2

OCTOBER 30, 2019

Respectfully submitted,

Scott Franson
Attorney No. 27839-49
Deputy Consumer Counselor

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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VERIFIED DIRECT TESTIMONY OF

LANE KOLLEN

ON BEHALF OF

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

OCTOBER 30, 2019

STATE OF INDIANA

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned both a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in Theology from Luther Rice University. I am a Certified Public Accountant, with a practice license, Certified Management Accountant, and Chartered Global Management Accountant. I am a member of numerous professional organizations.

I have been an active participant in the utility industry for more than thirty years, both as an employee and as a consultant. Since 1986, I have been a consultant with J. Kennedy and Associates, Inc., providing services to state government agencies and consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, auditing, tax, financial, and planning functions. From 1974 to 1976, I was employed by a contractor to Ohio Bell Telephone Company and Buckeye Cablevision and installed underground cable.

I have appeared as an expert witness on accounting, tax, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on hundreds of occasions, including the Indiana Utility Regulatory Commission ("Commission").[1]

Q. On whose behalf are you providing testimony?

A. I am providing testimony on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

B. Purpose

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) summarize the OUCC's proposed base and rider revenue requirements recommendations, including the effects of recommendations addressed by other OUCC witnesses, 2) address specific base and rider revenue requirement issues, including regulatory asset deferrals and amortizations, 3) address the termination of the IGCC Rider (Contract 61), and 4) address certain provisions of the Credits Rider (Contract 67).

C. Summary

Q. Please summarize your testimony.

A. I recommend a net reduction of at least $130.361 million from the Company's present rates, or a net reduction of $564.631 million to the Company's $434.270

[1] I provide more detailed information regarding my qualifications and regulatory appearances in my Exhibit___(LK-1).

million effective net increase based on numerous OUCC recommendations and adjustments to the revenues and costs included in the forecast test year. On the following table, I summarize the effect on the Company's requested net increase of each OUCC recommendation and also identify the OUCC witness who addresses each adjustment. I quantify the revenue requirement effect of each specific adjustment that I address, as well as the revenue requirement effect of each rate base and operating expense recommendation addressed by the other OUCC witnesses, including the depreciation rates and cost of capital recommendations addressed by OUCC witness Mr. David Garrett.[2]

[2] The calculations of the amounts shown on the table are detailed in my electronic workpapers, which have been filed in live format and with all formulas intact in conjunction with my Direct Testimony.

Duke Energy Indiana, LLC
Summary of Indiana Office of Utility Consumer Counselor Recommendations
IURC Cause No. 45253
Test Year Ended December 31, 2020
$ Millions

	Total Co. Adjustment Amount Before Gross-Up	Jursidictional Adjustment Amount Before Gross-Up	Jursidictional Adjustment Amount After Gross-Up	OUCC Witness
Duke Energy Indiana, LLC Requested Increase			$ 394.570	
Adjustment for Utility Receipts Tax (Estimate per COSS24-MTD)			41.200	
Adjustment for Revenues Remaining in Riders			(1.500)	
Duke Energy Indiana, LLC Effective Increase			$ 434.270	
Effects on Base Rate Increase of OUCC Rate Base Recommendations				
Remove Crane Microgrid and Battery Storage Project from Plant In Service			(0.709)	Alvarez
Reduce ROW Costs in Plant In Service			(1.653)	Hand
Remove Other Solar Projects from Plant In Service			(0.285)	Haselden
Reflect Target Fuel Inventories for Cayuga and Edwardsport			(0.102)	Kollen
Reduce Fuel and Materials and Supplies Inventories For Amounts Financed By Vendors			(2.058)	Kollen
Remove Prepaid Pension Asset			(10.883)	Kollen
Remove Gallagher Units 2 and 4 from Rate Base to Reflect Levelized Recovery			(2.258)	Kollen
Remove Coal Ash Pond Remediation Regulatory Assets			(16.095)	Armstrong
Remove Remainder of Regulatory Assets to Reflect Levelized Recovery			(16.867)	Kollen
Adjust Accumulated Depreciation for Changes in Depreciation Expense			3.930	Kollen
Effects on Base Rate Increase of OUCC Operating Income Recommendations				
Include Unbilled Revenues		(28.853)	(28.971)	Kollen
Increase Residential Margins for Adjusted Sales Forecast		(42.266)	(42.439)	Watkins
Reflect 100% of Existing Non-Native Load Bundled Short-Term Contract Margins		(12.742)	(12.794)	Boerger
Remove Budgeting Error In O&M Expense Account 575 Market Monitoring And Complian	(2.000)	(1.998)	(2.007)	Kollen
Remove Incentive Compensation Tied to Financial Performance	(12.401)	(11.738)	(11.786)	Kollen
Reduce Payroll Taxes Associated with Incentive Compensation Removal	(0.550)	(0.521)	(0.523)	Kollen
Reduce Fixed O&M and Major Outage Expense for Edwardsport IGCC	(50.830)	(45.936)	(46.124)	Alvarez
Reduce Fixed O&M and Major Outage Expense for Other Generating Units	(80.000)	(72.298)	(72.594)	Alvarez
Reduce Vegetation Management Expense	(16.600)	(16.600)	(16.668)	Hand
Reduce Storm Damage Expense	(6.700)	(6.700)	(6.727)	Alvarez
Eliminate Credit/Debit Card Convenience Fees	(4.528)	(4.528)	(4.547)	Aguilar
Remove Amortization Expense for Ash Pond Regulatory Asset	(12.098)	(12.068)	(12.118)	Armstrong
Remove Amortization Expense for Vegetation Mgmt Regulatory Asset	(3.078)	(3.071)	(3.083)	Kollen
Remove Remainder of Rate Base Reg Assets Amort in Order to Reflect Levelized Recovery	(28.388)	(28.318)	(28.434)	Kollen
Remove Depreciation Expense for Gallagher Units 2 and 4	(25.640)	(23.478)	(23.574)	Kollen
Remove Depreciation Expense for Crane Microgrid and Battery Storage Project	(0.370)	(0.339)	(0.340)	Alvarez
Remove Depreciation Expense for Other Solar Projects	(0.149)	(0.136)	(0.137)	Haselden
Remove Depreciation Expense for ROW Plant Reductions	(0.533)	(0.532)	(0.534)	Hand
Reduce Depreciation Expense Due to a Change in Depreciation Rates	(109.260)	(103.147)	(103.569)	Garrett
Reflect Reduction in Indiana Current Income Tax Expense	-	(2.017)	(2.026)	Kollen
Effects on Base Rate Increase of OUCC Rate of Return Recommendations				
Reduce ADIT in Capital Structure Related to OUCC Adjustments to Rate Base			8.319	Kollen
Increase ADIT in Capital Structure to Exclude Amounts Not Related to Rate Base			(10.559)	Kollen
Reduce Long Term Debt Rate, Including Permanent Short Term Debt Rate			(7.687)	Garrett
Reflect Return on Equity of 9.0%			(74.209)	Garrett
Reflect Levelized Recovery of Remaining Regulatory Assets			30.821	Kollen
Reflect Levelized Recovery of Remaining Regulatory Liabilities			(19.778)	Kollen
Total OUCC Base Revenue Requirement Adjustments			$ (539.069)	
Effects on Credit Rider (Contract 67) of OUCC EADIT Amortizations				
Reflect Amortization of Protected EADIT Regulatory Liability Over 3 Years	(10.000)	(9.516)	(9.555)	Blakley
Reflect Amortization of Indiana EADIT	(4.759)	(4.529)	(4.548)	Blakley
Reflect One-Time Credit of DEBS EADIT	(3.046)	(2.898)	(2.910)	Kollen
Effects on Reliability Rider (Contract 70) of OUCC Non-Native Sales Margins				
Reflect 80%/20% Non-Native Load Other Sales Margins		(0.750)	(0.753)	Boerger
Reduce Utility Receipts Tax for OUCC Adjustments			(7.796)	Kollen
Net Revenue Increase (Decrease) after OUCC Recommendations			$ (130.361)	

Note: The Gross-Up Represents the Effects of Bad Debt Expense and Public Utility Fees

I also recommend that the Commission deny the Company's requests for retroactive deferrals of certain operation and maintenance expenses (Customer Connect platform, and pension settlement accounting) that have been or will be expensed prior to the date when rates are reset in this proceeding. These requests for retroactive deferrals have no effect on the revenue requirement in this proceeding, but will result in increases in the revenue requirements in future base rate proceedings.

In addition, I recommend that the Commission incorporate the ongoing reductions in the Edwardsport IGCC plant-related cost curve due to the growth in accumulated depreciation and ADIT after the end of the test year in the Credits Rider (Contract 67). This recommendation has no effect on the base revenue requirement in this proceeding, but will affect the Credits Rider revenue requirement in subsequent years.

Finally, I recommend that the Commission incorporate certain other increases and reductions in the revenue requirement in the Credits Rider. These include the reductions in the cost curve for regulatory assets as they are recovered and the increase in the cost curve for regulatory liabilities as they are refunded. These include the reduction in the Gallagher 2 and 4 O&M expense when those generating units are retired in December 2022. These also include the temporary increase in current income tax expense to reflect an effective Indiana state income tax rate of 5.375% in the test year, an effective rate of 5.25% in the first six months of 2021, and then the final rate of 4.90% on July 1, 2021. This recommendation is consistent with my recommendation to use the 4.90% Indiana state income tax rate that will be effective on July 1, 2021 to set the current income tax expense component and for the gross revenue conversion factor in the base revenue requirement.

II. RATE BASE ISSUES

A. Fuel and Materials and Supplies Inventories

1. Fuel Inventory Forecast

Q. Describe the fuel and materials and supplies inventories included in rate base.

A. The Company included total Company $125.175 million in fuel inventories and $307.603 million in materials and supplies inventories in rate base.[3] These amounts are based on the Company's forecast of the quantity and cost of these inventories at December 31, 2020.

Q. Are the coal inventories included in rate base reasonable?

A. No. The Company's forecast coal inventories at Cayuga and Edwardsport are greater than the target number of days burn at those generating stations.[4] The Company's target days burn for both stations is 45 days.[5] However, the Company included 47 days burn for Cayuga and 46 days burn for Edwardsport.[6]

[3] Petitioners' Exhibit 4-F (DLD). The total Company fuel inventory amounts are provided in greater detail in WP RB1- SES and response to 1-5-12(2)(c)(ii). The total Company materials and supplies inventory amounts are provided in greater detail in WP RB4 – DLD.

[4] Response to 1-5-12(2)(c)(ii). I have attached a copy of this response as my Exhibit___(LK-2).

[5] Direct Testimony of Brett Phipps at 6.

[6] Response to 1-5-12(2)(c)(ii). I have attached a copy of this response as my Exhibit___(LK-2).

Q. Are the forecast cost inventories at Cayuga and Edwardsport reasonable?

A. No. The forecast inventory quantities and costs, by definition, are based on assumptions. It is reasonable for the Commission to assume that the Company will manage its fuel inventories to the target number of days burn. It is not reasonable for the Company or the Commission to assume that the Company will intentionally stockpile inventory quantities greater than the target number of days burn.

Q. What is your recommendation?

A. I recommend that the Commission reduce the fuel inventories to the target number of days burn. This is the maximum amount that should be included in rate base, especially for a forecast test year.

Q. What is the effect of your recommendation?

A. The effect is a reduction in total Company rate base of $1.467 million and a reduction in the retail revenue requirement of $0.102 million.

2. Fuel and Materials and Supplies Inventories Financed By Vendors

Q. Does the Company finance its fuel and materials and supplies inventories exclusively with equity and long-term debt?

A. No. The Company's equity and debt investors finance only the portions of the fuel and materials and supplies inventories that are not financed by its vendors. The Company records its vendor financing in accounts payable until the vendors are paid pursuant to the terms of the contracts and purchase orders between the Company and its vendors.

The fuel and materials and supplies inventories and accounts payables are inherently interrelated and arise from the same transactions. The recurring purchases and consumption of fuel and materials and supplies inventories results in recurring accounts payables and payments. There are always fuel and materials and supplies inventories and there are always related accounts payables.

Q. What are the ratemaking implications of the vendor financing for these inventories?

A. The ratemaking should reflect the reality that the portions of the fuel and materials and supplies inventories financed by its vendors are cost-free capital. The Company should not earn a rate of return on the fuel and materials and supplies inventories that are not financed by its investors. The Commission can remedy this error in the Company's filing through either a reduction to rate base for the inventories accounts payable or an adjustment to the capitalization and cost of capital for the cost-free capital. Either approach ensures that the Company does not improperly recover a return on the fuel and materials and supplies inventories that are financed by its vendors, not its investors.

Q. Is the vendor financing sufficiently significant that the Commission should address it in this proceeding?

A. Yes. The vendor financing for fuel inventories has averaged $28.877 million per month from January 2018 through August 2019, the most recent month for which actual information was available in response to discovery.[7] The vendor financing for materials and supplies inventories has averaged $0.586 million per month from January 2018 through August 2019, the most recent month for which actual information was available in response to discovery.[8]

Q. What is the Company's forecast for fuel and materials and supplies accounts payable at December 31, 2020?

A. The Company forecasts $15.292 million for fuel inventories accounts payable[9] and *negative* $2.487 million for materials and supplies inventories accounts payable.[10]

Q. Are the forecast accounts payable amounts at December 31, 2020 reasonable?

A. No. Fundamentally, these are forecast amounts and the forecast amounts are unreasonably low. The forecast amounts should be assessed against actual amounts to assess whether they are reasonable, not simply accepted as reasonable. Perhaps rather obviously, the amounts are not certain or even known and measurable. In fact, only the Company's forecast of coal fuel inventories accounts payables changes from the actual payables at December 31, 2018. The Company's forecast of oil and natural gas payables at December 31, 2020 is the same as the actual at December 31,

[7] Response to OUCC 31.5, Attachment OUCC 31.5-A. I have attached a copy of this response as my Exhibit___(LK-3).
[8] Response to OUCC 31.6. I have attached a copy of this response as my Exhibit___(LK-4).
[9] Response to OUCC 31.5, Attachment OUCC 31.5-A. I have attached a copy of this response as my Exhibit___(LK-3).
[10] Response to OUCC 31.6. I have attached a copy of this response as my Exhibit___(LK-4).

2018, which is reasonable. However, the Company's forecast of coal inventories payables at December 31, 2020 is significantly lower than the actual average since January 2018 and only 57% of the actual amount at December 31, 2018. It is only 48% of the Company's forecast for January 2020. This is unreasonable based on actual historic payables amounts.

The Company's forecast for materials and supplies inventories accounts payables starting in August 2019 is $0.513 million each month through the end of the test year, except for December 2019, which the Company forecasts at negative $0.487641 million, and December 2020, which the Company forecasts at negative $2.487641 million, the same amount as it forecasts at December 2019 less another $2.000 million.[11] In contrast, the actual amount at December 2018 was $0.656 million, one of the highest amounts during 2018, and certainly not negative.[12] I should note that a negative indicates a prepayment, not a payable. There is no evident reason why the Company would forecast a negative payable in December 2019 and December 2020, unlike any other forecast month in 2019 and 2020 and unlike any actual month in 2018 and 2019.

Q. What is your recommendation?

A. I recommend that the Commission subtract the accounts payable for the fuel and materials and supplies inventories from rate base. This will ensure that the Company recovers a return on only the portions of these inventories that are financed by its

[11] *Id.*
[12] *Id.*

investors. I also recommend that the Commission use the average actual coal inventories accounts payable and the average actual materials and supplies inventories accounts payable from January 2018 through August 2019 for this purpose rather than the Company's unreasonable forecast amounts at December 31, 2020.

Q. What is the effect of your recommendation?

A. The effect is a reduction in total Company rate base of $29.463 million and a reduction in the retail revenue requirement of $2.058 million.

B. Prepaid Pension Asset

Q. Describe the Company's request to include a "prepaid" pension asset in rate base.

A. The Company included a $142.803 million prepaid pension asset in rate base for the first time in this rate case proceeding. The Company never sought to include a prepaid pension asset in rate base in prior rate case proceedings. The Company's request is described by Ms. Diana Douglas.[13] Ms. Douglas claims that the Company "funded" the prepaid pension asset and that it contributes to a reduction in pension cost. Ms. Douglas defines the prepaid pension asset as "the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of

[13] Revised Direct Testimony of Diana Douglas at 38-39.

accrued pension cost."[14]

Q. Did the Company ever seek or obtain Commission authorization for a "prepaid" pension regulatory asset?

A. No. The Company never sought and the Commission never authorized a prepaid pension regulatory asset for ratemaking purposes. This regulatory asset is simply an accounting "placeholder" initially recorded in response to changes in pension accounting requirements pursuant to generally accepted accounting principles ("GAAP") that the Company adopted in 2006.[15] The changes in pension accounting were summarized in SFAS 158 as follows.

> This Statement requires an employer that is a business entity and sponsors one or more single-employer defined benefit plans to:
>
> > Recognize the funded status of a benefit plan—measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation—in its statement of financial position. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree health care plan, the benefit obligation is the accumulated postretirement benefit obligation.
> >
> > Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost pursuant to FASB Statement No. 87, *Employers' Accounting for Pensions*, or No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* Amounts recognized in accumulated other comprehensive income, including the gains or losses, prior service costs or credits, and the transition asset or obligation remaining from the initial application of Statements 87 and 106, are adjusted as they are subsequently recognized as components of net

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[14] *Id.*,38.

[15] Statement of Financial Accounting Standards ("SFAS") 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* issued by the Financial Accounting Standards Board.

periodic benefit cost pursuant to the recognition and amortization provisions of those Statements.

In accordance with the requirements of SFAS 158 (now codified in ASC 715), the Company recorded the initial net funded status of its pension and OPEB funds on its general ledger and reported it on the balance sheet in 2006.[16] SFAS 158 defined the net funded status as the difference between the fair value of pension trust fund assets and the projected benefit obligation (pension liability). The Company's qualified pension plan was underfunded and the Company recorded a net pension liability.

In response to the issuance of SFAS 158, the FERC Office of Enforcement issued accounting and reporting guidance in OE Docket No. AI07-1-000 styled as "Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans."[17] Consistent with SFAS 158, the FERC directed jurisdictional utilities to record a regulatory asset if it had a net pension liability or a regulatory liability if had a net pension asset. The FERC accounting guidance noted that the regulatory asset was simply the difference between the fair value of the pension trust fund assets and pension liability at each measurement date and that it was not amortized to pension cost (expense or capital).[18]

In accordance with the requirements of SFAS 158, the Company also recorded the cumulative effect of the *unrealized* gains and losses in accumulated

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[16] Applicable pages of DEI's 2006 FERC Form 1 and response to OUCC 33.8. I have attached copies of both as my Exhibit___(LK-5).

[17] Issued on March 29, 2007. I have attached a copy of this FERC accounting and reporting guidance as my Exhibit___(LK-6).

[18] *Id.*

other comprehensive income (AOCI"), a component of common equity.[19] In effect, the entry to AOCI offset the fair value of the pension trust fund assets with the amount of the *unrealized* gains or losses that had not yet been realized or recorded to pension cost.

Finally, as a regulated utility, the Company then reclassified the unrealized gains and losses from AOCI to a regulatory asset because the unrealized gains or losses ultimately will be realized and included in the pension costs reflected in regulated rates.

Q. Did the adoption of SFAS 158 and the FERC accounting and reporting guidance require the Company to fund the regulatory asset or obtain investor financing to do so?

A. No. The prepaid pension asset is a non-cash regulatory asset, similar to other non-cash regulatory assets and liabilities that are not included in rate base or as a zero-cost component of capitalization because the Company has not incurred and will not incur the cash cost until some future date. When the Company adopted SFAS 158, it had no effect on the pension trust fund assets, no effect on the pension liability, no effect on pension funding requirements, and no effect on capitalization or financing.

When the Company adopted SFAS 158, it did not issue common equity or debt to finance the underfunded pension liability. In accordance with the FERC accounting guidance, it simply recorded the required regulatory asset for the net underfunded liability and, in accordance with SFAS 158, it also recorded a

[19] *Id.*

regulatory asset for the unrealized gains and losses.

Q. Is the prepaid pension asset similar to other non-cash balance sheet amounts that are not included in rate base or capitalization?

A. Yes. This non-cash regulatory asset is similar to other non-cash balance sheet amounts that are not included in rate base or capitalization for ratemaking purposes. For example, the Company does not include any so-called asset retirement obligations ("AROs") assets or liabilities as additions to or subtractions from rate base because these amounts do not represent cash payments or receipts. Similarly, the Company does not include any so-called SFAS 109 regulatory assets or liabilities as additions to or subtractions from rate base or in the zero-cost ADIT component of capitalization because they do not represent cash payments or receipts.

Q. Do you have further evidence that the prepaid pension asset was not financed by the Company's equity and debt investors?

A. Yes. As I noted previously, if the Company had financed the prepaid pension asset, then its capitalization necessarily would be greater to reflect this fact. Yet, DEI's capitalization is not greater and does not reflect the issuance of equity and debt to finance the prepaid pension asset.

In fact, in discovery, the Company was asked to provide a reconciliation between rate base and capitalization similar to a reconciliation that Duke Energy Kentucky ("DEK") recently filed in its pending rate case before the Kentucky Public Service Commission ("KPSC"). This is not a difficult task, yet the Company objected to the OUCC request and refused to provide the reconciliation. Based on the DEK reconciliation, the DEI reconciliation would have shown that the Company did not finance the prepaid pension asset and demonstrated that the prepaid pension asset should not be included in rate base.

Indeed, that is what the DEK reconciliation demonstrates. Importantly, and unlike DEI's claim in this Indiana proceeding, DEK did not include a prepaid pension asset in rate base in the Kentucky proceeding.[20] DEK correctly recognized that it actually had not financed the prepaid pension asset. DEK demonstrated that fact through the reconciliation of rate base to capitalization.[21] DEK made no reconciling adjustment to reduce capitalization by the amount of the prepaid pension asset as would be required if DEK actually had financed the prepaid pension asset, but simply chose not to include it in rate base.[22]

On the one hand and in this proceeding, is DEI's request to include its prepaid pension asset in rate base and its claim that it financed that regulatory asset. Yet, it failed to provide any proof for that claim and refuses to provide a reconciliation of rate base to capitalization, which would either prove or disprove that claim. On the other hand and in the KPSC proceeding, is DEK's decision not to include its prepaid pension asset in rate base and its reconciliation of rate base to capitalization, which proves conclusively that DEK did not finance its prepaid pension asset.

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[20] KPSC Case No. 2019-00271 Schedule B-1, Schedule B-5, Workpaper WPB-5.1e and the reconciliation of the rate base to capitalization filed as Filing Requirement 16(6)(f). I have attached copies of each of these as my Exhibit___(LK-7).

[21] *Id.*

[22] *Id.*

Q. What is the correct approach?

A. The correct approach is to exclude any prepaid pension asset from rate base. The Company does not incur a carrying cost on the prepaid pension asset. The Company has not funded or financed the prepaid pension asset that it recorded. At best, the prepaid pension asset is comparable to a regulatory asset in the sense that it ultimately has the right to recover the underfunded accumulated pension benefit obligation through pension "cost." However, that right to recover is merely an accounting "placeholder" that will reverse as the pension cost is calculated and recovered in future years, including the return on the actual plan assets and the interest expense on the actual accumulated pension benefit obligation.

Q. If the Commission includes a prepaid pension asset in rate base, has the Company correctly calculated the amount that should be included in rate base?

A. No. First, the Company calculated the amount based on various assumptions that do not reflect the difference between the contributions to the pension trust fund by DEI or on behalf of DEI specifically and the "costs" recovered from customers. The Company has not tracked the "costs" recovered from customers through rates; rather, these "costs" are the actuarially calculated "costs" each year, although it has done so only since 2009.[23] The Company's base rates have been in effect since 2004 and have not changed to reflect the actuarially calculated "costs" each year.

[23] Responses to OUCC 17-33 and 17-34 (Attachment is Confidential). I have attached copies of these responses as my Exhibit___(LK-8).

Second, the prepaid pension asset calculated based on the actuarially calculated "costs" does not reflect the fact that a portion of those "costs" has been capitalized and is already included in rate base in the plant in service amounts. A portion of the pension "costs" is capitalized to construction work in progress ("CWIP"), then closed to plant in service when the asset is placed into service. This capitalized portion of the pension "costs" is included in rate base and the return on and of this portion of the pension "costs" is included separately in the revenue requirement. Consequently, a portion of the prepaid pension asset regulatory asset accounting placeholder is due to the plant in service included in rate base and a portion is due to the pension "expense" included in the revenue requirement.

Q. How much of the pension "cost" has been capitalized and is included in rate base and how much has been expensed?

A. On average, the Company capitalized 27.2% of its actuarially calculated pension "costs" to CWIP/plant in service and expensed the remaining 72.8% over the last ten years.[24]

Q. What is your recommendation?

A. I recommend that the Commission exclude the entirety of the prepaid pension asset from rate base. It is a non-cash regulatory asset and accounting placeholder. The regulatory asset was not financed by the Company's equity and debt investors. In

[24] Response to OUCC 33.9. This is the average of the annual percentages capitalized for the years 2010 through 2018. The Company was not able to provide this information for years prior to 2010. I have attached a copy of this response as my Exhibit___(LK-9).

addition, despite the Company's testimony describing the alleged conceptual basis for the prepaid pension asset, the actual calculation does not accurately reflect the amounts that DEI contributed, the amounts recovered from customers, or the fact that a portion of pension "costs" have been capitalized and are included in plant in service in rate base.

In the alternative, and at a minimum, I recommend that the Commission reduce the prepaid pension asset to remove the portion of the prepaid pension asset due to the "contributions" and pension "costs" asset that have been capitalized to plant and not expensed. The Company should not be allowed to earn a return on both the prepaid pension asset and the capitalized portion already included in the plant in service amounts in rate base.

Q. What are the effects of your recommendations?

A. The effect of excluding the prepaid pension asset is a reduction in total Company rate base of $150.740 million and a reduction in the retail revenue requirement of $10.883 million. The effect of reducing the prepaid pension asset to exclude the capitalized portion is a reduction in total Company rate base of $41.001 million and a reduction in the retail revenue requirement of $2.960 million.

C. Regulatory Assets And Regulatory Liabilities

1. Overview of Requested Regulatory Assets

Q. Describe the Company's request for recovery of regulatory assets.

A. The Company seeks recovery of $618.619 million in regulatory assets. The Company included $433.587 million as additions to rate base and excluded the remaining $185.032 million from rate base. The Company proposes amortization periods that vary according to the specific regulatory asset. The Company reflected no regulatory liabilities as subtractions from rate base and no negative amortization expense.[25]

The following table lists each of the proposed regulatory assets, the amounts forecast at December 31, 2020, and the requested annual amortization expense separated into those regulatory assets that the Company included in rate base and those that it excluded from rate base.[26] The Company's calculation of annual amortization expense is based on its forecast of the regulatory asset amounts at June 30, 2020, coincident with the date it assumed that base rates will be reset.[27]

[25] The Company also requests authorization to defer the O&M expenses incurred since January 1, 2018 for the development and implementation of the new Customer Connect platform; however, the Company has not included a Customer Connect regulatory asset in rate base or amortization expense in operating income in the revenue requirement for the test year.

[26] MSFR Workpaper DA2-DLD.

[27] *Id.*

Duke Energy Indiana, LLC
Proposed Regulatory Asset Amortization
($ Millions)

Description	Dec 31, 2020 Balance As Adjusted	Proposed Annual Amortization
	(A)	(D)
Rate Base Related Accounts		
182140-Noblesville Carrying Costs - Retail	$ 1.777	$ 0.132
182150-Noblesville Deferred Depreciation - Retail	0.735	0.054
182141-Noblesville Carrying Costs - Retail	8.497	0.629
182151-Noblesville Deferred Depreciation - Retail	4.528	0.335
182113-Post in Service Carrying Costs-NOX	0.432	0.173
182222-Madison and Henry County Carrying Costs - Retail	6.994	0.359
182232-Madison & Henry County Deferred Depreciation - Retail	3.406	0.175
182221-Madison and Henry Carrying Costs - Retail	16.587	0.851
182231-Madison & Henry Deferred Depreciation - Retail	6.994	0.359
182570-Other Production Plant AFUDC Continuation - Retail	0.268	0.023
182580-Other Production Plant Depreciation Deferral - Retail	2.103	0.183
182670-Other Production Plant AFUDC Continuation - Retail	2.386	0.207
182680-Other Production Plant Depreciation Deferral - Retail	5.186	0.451
182202-Net Book Value of Gallagher Units 1 & 3 and Plan "B" Gas Conv.	25.451	5.090
182365-Deferred Depreciation Gallagher Baghouses Units 2 & 4	3.060	1.224
182454-Net Book Value of Wabash River Unit 6	16.022	2.136
182114-Post in Service Carrying Costs-Environmental Phase I	21.376	1.245
182471-Reg Asset - Coal Ash Pond - IN Retail	186.709	10.669
TBD-Reg Asset - Coal Ash Pond - IN Retail - PISCC	25.006	1.429
182602-Post in Service Carrying Costs-CCR 40%	16.732	1.455
182608-CCR - Deferred Depreciation - 40%	11.374	0.989
182611-CCR Plan Development - 20%	2.189	0.876
182609-CCR Deferred O&M - 20%	5.446	2.178
TBD- Retail Native SO2 EA	9.520	0.828
182916-Post in Service Carrying Costs - Crane Solar	2.190	0.083
182475-Post in Service Carrying Costs-Federal Mandate - 20%	0.737	0.295
182643-Federal Mandate - Deferred Depreciation - 20%	0.249	0.099
182640-Federal Mandate - Deferred O&M Costs - 20%	2.137	0.855
182641-Federal Mandate - Carrying Costs on Def O&M - 20%	0.426	0.170
182913-Post in Service Carrying Costs-TDSIC Rider 65 - 20%	18.902	2.908
182656-TDSIC - Deferred Depreciation - 20%	8.681	1.336
182650-TDSIC - Deferred O&M Costs - 20%	15.644	2.407
182651-Post in Service Carrying Costs-TDSIC Deferred O&M - 20%	1.843	0.283
Total Rate Base Related Accounts	$ 433.587	$ 40.486
Expense Related Accounts		
TBD-IGCC Outage Cost Deferral	$ 46.401	$ 6.629
182625-IGCC Deferred Expenses	93.267	19.500
182915-Post in Service Carrying Costs - AMI	12.483	1.314
182655-AMI - Deferred Depreciation	17.727	1.866
TBD-Vegetation Management Deferral	9.235	3.078
182201-Retail Purchased Power	0.151	0.060
182250-MISO Cost Adder	3.111	1.245
182460-Deferred Audit Costs	0.119	0.048
182718-DEI 2019 Rate Case (3)	2.413	0.965
182657-Demand Discount	0.125	0.050
Total Expense Related Items	$ 185.032	$ 34.755
Total Proposed Regulatory Asset Amortization	**$ 618.619**	**$ 75.241**

Q. Describe how the Company's actual cost curve declines as the regulatory assets are amortized.

A. The Company's actual cost curve declines as the regulatory assets are amortized. This occurs for one or two reasons depending on whether the regulatory asset is included in rate base. First, the amortization expense ceases when the regulatory asset is fully amortized. This occurs for those regulatory assets included in rate base as well as those that are excluded from rate base. Second, the cost to finance (return on) the regulatory asset declines as the regulatory asset is amortized, ultimately to zero. This occurs only for those regulatory assets included in rate base.

Q. Why is this important?

A. This is important because the Company's base rates set in this proceeding will not decline to match the declining cost curve after the test year until the next base rate case proceeding when base rates are again reset. That means the Company inevitably will overrecover the return on and return of these regulatory assets. The longer the time period between base rate case proceedings, the greater the overrecovery, all else equal.

Q. Does the Company acknowledge this mismatch and propose a solution?

A. Yes. The Company proposes to offset the recovery included in base rates for the reductions in amortization expense through credits in the Credits Rider.[28]

[28] Revised Direct Testimony of Diana Douglas at 59: "The Company plans to include credits in its Credits Rider when the amortizations included in base rates end."

Q. Does the Company's proposed solution address the reductions in the return on rate base as the regulatory asset is amortized for those regulatory assets included in rate base?

A. No. Consequently, the Company will continue to recover the return on the regulatory assets included in rate base in this proceeding until base rates are reset at some date in the future even as the cost curve continuously declines due to the decline in the return on rate base for those regulatory assets included in rate base.

Consider the following illustration of this problem. Assume that the Commission allows $100 million for Regulatory Asset X in rate base with an amortization period of five years. Assume also that the grossed-up rate of return is 10%. On this basis, the Commission would include $30 million in the base revenue requirement, consisting of $10 million for the return on rate base and $20 million for the amortization expense.

On this basis, the Company will recover $30 million each year through base revenues until base rates are reset at some date in the future. The base revenue requirement will not change even though the cost curve declines, thus creating a mismatch, all else equal. More specifically, the cost curve will decline from $30 in year 1 to $28 million in year 2, to $26 million in year 3, to $24 million in year 4, to $22 million in year 5, and to $0 in year 6, which will remain at $0 in each year thereafter. Under the Company's limited solution, it would provide a credit of $20 million starting in year 6 that will reduce the net recovery through base rates and the Credits Rider to $10 million annually in that year and each year thereafter.

However, the Company will overrecover $2 million in year 2, $4 million in year 3, $6 million in year 4, $8 million in year 5, and a net $10 million each year thereafter until base rates are reset at some date in the future. If base rates are not reset for 15 years, then the Company will overrecover $120 million compared to the actual cost curve even with the Company's proposed $20 million credit starting in year 6, all else equal. In this illustration, the Company will recover more than twice its actual costs related to this regulatory asset, a significant harm to customers and a significant windfall to the Company.

Q. Are there ratemaking recovery alternatives that ensure the Company recovers the return of and the return on the regulatory assets, no more and no less, and that minimize the effect on customers in the base revenue requirement?

A. Yes. First and foremost, the Commission should ensure that the Company recovers only the allowed return of and the return on the allowed regulatory assets, no more and no less. The Commission should ensure that the reduction in the revenue requirement each year is timely reflected in lower rates through the Credits Rider so that the revenues recovered through base rates are offset by the reduction in the revenue requirement through the Credits Rider. This is equitable to the Company and its customers and is an essential customer safeguard.

Second, the Commission can minimize the effect on customers of the return on the regulatory assets included in rate base in the test year revenue requirement by levelizing (annuitizing) the return on and return of the regulatory asset over the amortization period. This approach converts the declining cost curve into a flat cost curve for those regulatory assets included in rate base and is similar in concept to a mortgage style payment. The flat cost curve is calculated to equal the net present value of the declining cost curve.

Third, the Commission can minimize the effect on customers by extending the amortization periods compared to those proposed by the Company. The Commission has complete discretion as to the amortization period and is not bound by prior service lives for prematurely retired generating units.

Q. Provide an illustration that contrasts the declining cost curve as regulatory assets are amortized with the flat cost curve using a levelized (annuitized) form of cost recovery.

A. In this illustration, I continue with the prior illustration for purposes of the declining cost curve assumed in the Company's filing. I contrast the declining cost curve with a flat (also referred to as a levelized or annuitized) cost curve that provides the same recovery each year over the amortization period similar in concept to a home mortgage. The net present value of the recovery under the declining cost curve and the levelized cost curve are the same. However, under the flat cost curve, the payments in the earlier years provide recovery of the entirety of the return on the principal amount of the regulatory asset, but less recovery of the principal compared to the amortization under the declining cost curve. Under the flat cost curve, the payments in the latter years provide recovery of the entirety of the return on the declining principal amounts of the regulatory asset, but more recovery of the principal compared to the amortization under the declining cost curve. The following table compares the annual recovery in the revenue requirement under the declining cost curve and under the flat cost curve.

Comparison of Declining Cost Curve
Compared to Flat (Levelized) Cost Curve
$ Millions

	Declining Cost Curve	Flat Cost Curve
Year 1	30.000	26.380
Year 2	28.000	26.380
Year 3	26.000	26.380
Year 4	24.000	26.380
Year 5	22.000	26.380

Q. What is your recommendation generally with respect to the return on and return of the proposed regulatory assets?

A. I recommend that the Commission levelize (annuitize) the recovery of all regulatory assets included in rate base in order to minimize the effects on customers. I also recommend that the Commission timely reduce rates to match the reductions in the cost curves for each regulatory asset through the Credits Rider, both for the regulatory assets included in rate base and those that are not included.

In addition, I recommend that the Commission utilize amortization periods of at least ten years for each regulatory asset. An amortization period of at least ten years affects only a limited number of regulatory assets and will minimize the effect of the recoveries on customers. An amortization period of at least ten years also recognizes that the duration between base rate case proceedings may be significantly more than 3 or 5 years. The Company's last base rate case proceeding was in 2004, or 15 years ago.

Finally, I recommend that the Commission reduce certain of the requested regulatory assets or require the establishment of regulatory liabilities for reasons that I address in subsequent sections of my testimony and that other OUCC witnesses address in their testimony.

2. Retired Generating Units Net Book Value

Q. Describe the Company's retired generating units and the related regulatory assets included in rate base and amortization expense.

A. The Company seeks recovery of regulatory assets for the remaining net book value of Wabash River 6 and Gallagher 1 and 3, including the Gallagher 1 and 3 baghouses and the Plan B conversion study costs.[29] The Company included $16.023 million in rate base for Wabash River 6 and $25.450 million for Gallagher 1 and 3, including the baghouses and Plan B conversion study costs. The Company seeks recovery of $2.136 million in amortization expense for Wabash River 6 and $5.090 million for Gallagher 1 and 3, including the baghouses and Plan B conversion study costs.

[29] Revised Direct Testimony of Diana Douglas at 30-34 and 96-98.

Q. When was Wabash River 6 retired from service?

A. Wabash 6 was retired from service on April 16, 2016.[30]

Q. When were the Gallagher 1 and 3 and related baghouses retired from service?

A. Gallagher 1 and 3 were retired on January 31, 2012.[31]

Q. Were there savings in operating expenses when the Company retired Wabash River 6 from service?

A. Yes. There were significant savings in non-fuel O&M expense. In 2016, the non-fuel O&M expense savings were $11.566 million compared to the $17.324 million in non-fuel O&M expense incurred in 2015, the last full calendar year of operation.[32] In each year thereafter, the annual non-fuel O&M expense savings was and continues to be $17.324 million. The cumulative savings through June 30, 2020 will be $72.199 million[33] on a total Company basis and $65.248 million on a retail jurisdictional basis.

Q. Were there savings in operating expenses when the Company retired Gallagher 1 and 3 from service?

A. Yes. There were significant savings in non-fuel O&M expense. In 2012 and each year thereafter, the annual non-fuel O&M expense savings was and continues to be

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[30] Response to IG 18.1. I have attached a copy of this response as my Exhibit___(LK-10).
[31] *Id.*
[32] Response to OUCC 29.11. I have attached a copy of this response as my Exhibit___(LK-11).
[33] The Company used June 30, 2020 as the date for the regulatory asset amounts used in the calculation of annualized amortization expense based on the assumption that base rates will be reset in this proceeding on or about that date.

$11.623 million.[34] The cumulative savings through June 30, 2020 will be $98.796 million on a total Company basis and $89.284 million on a retail jurisdictional basis.

Q. Did the Company reduce base rates or implement credits through the Credits Rider or elsewhere to reflect the non-fuel O&M expense savings due to the retirement of these generating units?

A. No. The Company continues to recover this O&M expense through the base revenue requirement, along with the return on rate base and other operating expenses, such as depreciation expense.

Q. Did the Company defer the savings in non-fuel O&M expense due to the retirement of these generating units?

A. No. The Company unilaterally retained the non-fuel O&M expense savings instead of implementing credits through the Credits Rider or deferring the savings as a regulatory liability. In contrast, the Company properly continued to record amortization expense equal to the depreciation expense that it would have recorded if Wabash River 6 and Gallagher 1 and 3 had remained in service.[35]

Q. Has the Commission authorized a regulatory asset or specific amortization period for the net book value of Wabash River 6?

[34] Response to OUCC 29.11. I have attached a copy of this response as my Exhibit___(LK-11). Attachment OUCC 29.11 shows that in 2011, Gallagher 1 incurred $6.843 million in non-fuel O&M expense and Gallagher 3 incurred $4.780 million in O&M expense, or a total for both units of $11.623 million.

[35] Revised Direct Testimony of Diana Douglas at 30-34 and 96-98.

A. No.[36] The Company has continued to amortize the Wabash 6 regulatory asset using the presently authorized depreciation rates.[37] It proposes to change the amortization expense to reflect an eight year amortization period starting July 1, 2020 ostensibly based on an "original retire date" of June 30, 2028.[38]

Q. Has the Commission authorized a regulatory asset or specific amortization period for the net book value of Gallagher 1 and 3 and Plan B conversion costs?

A. Yes.[39] The Company has continued to amortize the Gallagher 1 and 3 and Plan B conversion study costs using the presently authorized depreciation rates.[40] It proposes to change the amortization expense to reflect a five and a half year amortization period starting July 1, 2020 ostensibly based on an "original retire date" of December 31, 2025.[41]

Q. Why is that important?

A. It is important because in all these retirements, the Company acted unilaterally to retain the non-fuel O&M expense savings instead of crediting the savings through the Credits Rider or deferring the savings to a regulatory liability. At the same time, with respect to the Wabash River 6 retirement, the Company also acted unilaterally

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[36] Schedule RB4 indicates that the IURC issued an order "approving amortization and/or deferral" of the Wabash River 6 net book value in Cause No. 42359; however, the Commission did not address the retirement or deferral of the Wabash River 6 net book value in its order in that proceeding.

[37] Refer to MSFR Workpaper RB3-DLD.

[38] *Id.*

[39] Schedule RB4 indicates that the IURC issued an order "approving amortization and/or deferral" of the Gallagher 1 and 3 net book value and Plan B conversion study costs in Cause No. 43956; however, the Commission did not address the deferral of the non-fuel O&M expense savings in that proceeding.

[40] Refer to MSFR Workpaper RB3-DLD.

[41] *Id.*

to reclassify the net book value to a regulatory asset, and to continue depreciation expense in the form of ongoing amortization expense.

Q. What are your recommendations regarding the retired generating units?

A. I recommend that the Commission recognize regulatory liabilities for the non-fuel O&M expense savings and subtract these amounts from rate base. This is a reasonable and equitable result given the Company's continued recovery of the net book value of the retired generating units and the fact that there has been actual savings in non-fuel O&M expense that could have and should have been deferred as regulatory liabilities.

I also recommend that the Commission amortize these regulatory liabilities over 10 years consistent with my overall recommendation to amortize all regulatory assets over at least 10 years. However, if the Commission does not agree with my recommendation on that point, then I recommend that the Commission amortize these regulatory liabilities over the same amortization periods proposed by the Company for the regulatory assets (8 years for Wabash River 6 and 5.5 years for Gallagher 1 and 3, including the baghouses and Plan B conversion study costs).

In addition, I recommend that the Commission reflect the return on and return of these regulatory liabilities on a levelized (annuitized) basis, consistent with my overall recommendation to recover regulatory assets on this basis.

Q. What are the effects of your recommendations?

A. The recovery of these two regulatory liabilities on a levelized basis amounts to a reduction in the revenue requirement of $19.778 million.

3. Soon To Be Retired Generating Units

Q. Describe the Company's soon to be retired generating units.

A. The Company plans to retire Gallagher 2 and 4, including the baghouses on or about December 31, 2022.[42]

Q. Has the Company requested authorization to reclassify the net book value to a regulatory asset when the units are retired, to continue and reclassify the depreciation expense as amortization expense, and/or to defer the O&M expense savings to a regulatory liability?

A. No. However, based on the Company's unilateral actions with respect to Wabash River 6, it is likely that the Company again unilaterally will reclassify the net book value to a regulatory asset and reclassify depreciation as amortization expense. It also is likely that the Company again unilaterally will retain the O&M expense savings instead of reducing rates through the Credits Rider or deferring the savings to a regulatory liability absent Commission action in this proceeding.

Q. What are your recommendations?

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[42] Petitioner's Exhibit 14-A (JJS) at 380.

A. I recommend that the Commission address these issues in this proceeding to ensure that the Company recovers its actual reasonable costs and also to ensure that its customers are not harmed through front-loaded and excessive recovery. Consequently, I recommend that the Commission require the Company to reclassify the net book value to a regulatory asset at June 30, 2020. I recommend that the Commission levelize the recovery of the return on and of over the minimum ten years that I recommend for all regulatory assets. In addition, I recommend that when the amortization is completed, the Company be required to offset the continued recovery in base rates through a credit in the Credits Rider. Finally, I recommend that the Commission direct the Company to reduce rates for the non-fuel O&M expense savings after the units are retired as a credit in the Credits Rider.

Q. What are the effects of your recommendations?

A. The effect is a $20.550 million reduction in the retail revenue requirement for the test year. There will be additional reductions in the revenue requirement through the Credits Rider for the savings in the non-fuel O&M expense starting in 2023 and to offset the recovery through base rates of the return on and of the net book value after the net book value is fully recovered in July 2032, assuming that the Commission adopts a ten-year amortization period.

4. Coal Ash Pond Remediation Costs

Q. Have you quantified the effects of OUCC witness Ms. Cynthia Armstrong's various recommendations regarding the coal ash pond remediation regulatory assets?

A. Yes. Ms. Armstrong's primary recommendation is to disallow the entirety of the $211.716 million in proposed ash pond remediation regulatory assets for various reasons. The effect is a $28.213 million reduction in the retail revenue requirement, consisting of a $16.095 million reduction in the grossed-up rate of return on the regulatory asset and a $12.118 million reduction for the related amortization expense after expense gross-up.

Ms. Armstrong's alternative recommendation is to disallow the IDEM costs included by the Company in its regulatory asset balance and levelize the recovery for the remainder of the costs. The effect is an $18.290 million reduction in the revenue requirement, consisting of the reduction noted above of $28.213 million to remove from regular base rate recovery offset by an increase of $9.923 million to reflect the levelized recovery of the CCR cost portion of the regulatory asset.

5. Customer Connect Expense

Q. Describe the Company's request to defer the O&M expense incurred since 2018 and that it will incur going forward to develop and implement the Customer Connect platform.

A. The Company seeks authorization to defer the costs that it already has expensed since 2018 and that it otherwise will expense going forward to a regulatory asset, including carrying costs at the weighted cost of capital until the regulatory asset is included in the revenue requirement when base rates are again reset.[43] The Company estimates that approximately half the cost to develop and implement the Customer Connect platform will be charged to expense.[44]

Q. What is the magnitude of the Company's request to defer the O&M expense?

A. It is significant. The Company forecasts that it will defer $42.054 million in O&M expense plus another $13.833 million in carrying costs through December 31, 2025, assuming that the recovery of the regulatory asset is not included in base rates prior to that date.[45] Of course, the O&M expense may be more or less than forecast by the Company. In addition, the deferred carrying costs will continue to accrue if the recovery of the regulatory asset is not included in base rates starting on or before December 31, 2025.

Q. Describe the Company's request to defer the depreciation expense and post in-service carrying costs on the capitalized plant costs after the Customer Connect platform is placed in service.

A. The Company seeks authorization to defer the depreciation expense and post-in-service carrying costs on the capitalized plant costs at the weighted cost of capital to a regulatory asset until the regulatory asset is included in the revenue requirement when base rates are again reset.[46]

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[43] Revised Direct Testimony of Christa Graft at 27-28.
[44] *Id*.
[45] Response to OUCC 29.3, Attachment 29.3-A. I have attached a copy of that response as my Exhibit___(LK-12).
[46] Revised Direct Testimony of Christa Graft at 27-28.

Q. Describe the two components of the Company's request to defer the O&M expenses.

A. The first component is the request to retroactively defer development and implementation costs, including carrying costs that it will already have incurred and expensed prior to the date when base rates are reset in this proceeding. The Company has assumed that base rates will be reset on June 30, 2020 for purposes of calculating annualized amortization expense for its proposed regulatory assets. The second component is the request to prospectively defer these costs, including carrying costs until base rates are reset in a future proceeding.

Q. What is the magnitude of the Company's request to retroactively defer the O&M expenses plus carrying costs since January 1, 2018?

A. The Company seeks to retroactively defer $10.630 million in O&M expenses and carrying costs through June 30, 2020, the date the Company assumes base rates will be reset in this proceeding.[47] If allowed, the retroactive deferrals will continue to accrue carrying costs until base rates are reset in the next base rate case proceeding.

Q. Is it appropriate to authorize a regulatory asset retroactively for O&M expenses and carrying costs incurred in prior periods?

[47] Response to OUCC 29.3, Attachment 29.3-A. I have attached a copy of that response as my Exhibit___(LK-12).

A. No. If authorized, this request will allow the Company to recover at some date in the future amounts that it already has expensed. If this request is authorized, the Company will reverse the expenses and carrying costs incurred in the prior periods through a one-time increase to income when it records the regulatory asset. In effect, this will allow the Company to record a windfall to income in 2020 in exchange for harming customers in the form of increased customer rates when base rates are reset in the next base rate proceeding.

Q. Is it appropriate to authorize a regulatory asset for carrying costs on the prospective O&M expense deferrals?

A. No. The prospective O&M expense deferrals are sufficient to provide the Company recovery of the costs that it incurred for the development and implementation of the new platform.

The Commission should view the Company's request for carrying costs in a broader perspective than simply this single asset. The entirety of the Company's existing plant-related rate base at December 31, 2020 ($9,212.361 million requested) will continue to depreciate going forward and the cost curve will continue to decline until base rates are again reset in a future base rate proceeding. Against this reality, the Company is able to include certain incremental plant-related and other costs and recover those costs through various riders with no offset to reflect the declining cost curve on its existing plant-related rate base at December 31, 2020.

Historically, between rate cases, the utility was at risk for the increasing costs (depreciation expense and carrying costs) due to new assets. However, it was able to mitigate this risk through retention of the savings resulting from the declining cost curve due to existing assets. This interrelationship between increasing costs from new assets and decreasing costs from existing assets provides important protections to customers because the utility is incentivized to minimize the costs of the new assets between rate cases in order to maintain its authorized return.

In this case, the Company seeks to retain the savings from the declining cost curve due to existing assets while seeking to recover the incremental costs from new assets. This is inequitable and harms customers.

Q. Is it appropriate to authorize a regulatory asset for the depreciation expense and post-in-service carrying costs on the capitalized plant costs?

A. No. The same issues and concerns are implicated for the depreciation expense and post-in-service carrying costs on the capitalized plant costs as for the carrying costs on the deferred O&M expense. This request is inequitable and harms customers.

Q. What are your recommendations?

A. I recommend that the Commission deny the Company's request to retroactively defer the O&M expense incurred prior to the date when base rates are reset in this proceeding. I recommend that the Commission approve the Company's request to defer the expense incurred going forward, but explicitly limit this approval to expense incurred only through the in-service date of Customer Connect and clearly state that the Company is not authorized to defer post in-service O&M expense.

I recommend that the Commission deny the Company's request to defer carrying costs on the O&M expense deferred during the development and implementation period.

I recommend that the Commission deny the Company's request to defer depreciation expense and post in-service carrying costs after the Customer Connect platform is placed in service.

Q. What are the effects of your recommendations?

A. There are no effects on the revenue requirement in this proceeding beyond the deferral of the O&M expense in the test year, which is reflected in the Company's requested revenue requirement and rate increase.[48] However, there will be effects beyond the test year that will affect future base rate increases. If the Commission authorizes the Company's requests to defer carrying costs on the deferred O&M expense and to defer post-in-service depreciation and carrying costs on capitalized plant costs, the effects in those future cases will depend on the O&M expense incurred and deferred and the capitalized plant costs as well as the depreciation expense and carrying cost deferrals. These amounts will continue to compound throughout the time period between when rates are reset in this proceeding and when they are reset again in the next base rate proceeding.

6. Edwardsport IGCC Major Maintenance Outage Expense

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[48] Response to OUCC 29.2. I have attached a copy of that response as my Exhibit___(LK-13).

Q. Describe the Company's request to defer the Edwardsport major maintenance outage expense.

A. The Company proposes to defer $46.401 million in major maintenance outage expense that it forecasts it will incur in the test year. The Company also proposes to amortize the regulatory asset over seven years.

Q. Is the OUCC conceptually opposed to the requested deferral and amortization?

A. No. OUCC witness Mr. Anthony Alvarez addresses the Edwardsport O&M expenses, including the deferral and amortization expense. However, I am concerned that the actual outage expense may exceed the forecast expense and that the Company may defer more than the estimated $46.401 million and seek recovery of the additional expenses if the Commission does not establish reasonable parameters that limit the deferral amount.

Q. What is your recommendation?

A. I recommend that the Commission limit the deferrals for the test year outage to the actual expenses incurred or the estimated $46.401 million, whichever is less. Such a limitation will protect customers from any unexpected additional expenses and incentivize the Company to complete the outage in a timely and cost-effective manner.

7. Pension Settlement Expense

Q. Describe the Company's request for authorization to defer pension settlement

expense.

A. The Company seeks to defer the forecast pension settlement expense since January 1, 2019 and in future years. In other words, it seeks to retroactively defer the amounts that already have been or will expensed before base rates are reset in this proceeding and to prospectively defer amounts that otherwise will be expensed after June 30, 2020.

Q. What is the magnitude of the Company's request to retroactively defer the O&M expenses plus carrying costs since January 1, 2019?

A. The Company seeks to retroactively defer $4.338 million in O&M expenses through December 31, 2019 and an additional, but as yet unknown, amount in 2020 and future years. [49] The Company does not seek to include these costs in rate base and does not seek to recover amortization expense in this proceeding. Rather, the deferrals will be subject to recovery in the Company's next base rate case proceeding.

Q. Is it appropriate to authorize a regulatory asset retroactively for O&M expenses?

A. No. If authorized, this request will allow the Company to recover at some date in the future amounts that it already has expensed. If this request is authorized, the Company will reverse the expenses and carrying costs incurred in the prior periods through a one-time increase to income when it records the regulatory asset. In effect,

[49] Response to OUCC 31.1. I have attached a copy of that response as my Exhibit___(LK-14).

this will allow the Company to record a windfall to income in 2020 in exchange for harming customers in the form of increased customer rates when base rates are reset in the next base rate proceeding.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request to retroactively defer the costs since 2019 until base rates are reset in this proceeding, similar to my recommendation regarding the Company's request to retroactively defer the Customer Connect O&M expense and carrying costs since 2018.

Q. What is the effect of your recommendation?

A. There is no effect on the revenue requirement in this proceeding. However, there will be effects beyond the test year that will affect future base rate increases to recover the retroactive deferrals, similar to the effects that will result from the Company's request to retroactively defer Customer Connect O&M expenses and carrying costs. If the Commission authorizes the Company's requests to defer, the effects in those future cases will depend on the O&M expense incurred and deferred.

8. Incremental Vegetation Management Expense

Q. Describe the Company's request to defer incremental vegetation management expense from January 1, 2020 through the date new rates go into effect in this proceeding.

A. The Company seeks to increase its vegetation management expense by $18.470 million annually starting January 1, 2020 compared to the expense reflected in present rates and to defer the increased expense from January 1, 2020 through the date new rates go into effect in this proceeding.[50] The Company assumed that new rates will go into effect on July 1, 2020 and seeks recovery of the $9.235 million over a three-year amortization period. The Company does not seek to include the regulatory asset in rate base.

Q. Does the Company reflect an increase of $18.470 million in its filing as a proforma adjustment to expense?

A. No. The Company forecasts $38.931 million in the test year and seeks to increase this amount by $10.479 million.[51] OUCC witness Mr. Eric Hand addresses this expense issue.

Q. Why is this significant?

A. It is significant because the Company forecasts that it will incur $38.931 million in vegetation management expense in 2020 without the proposed increase. The deferral, if one is authorized should be based on the proposed increase in the test year, not the increase compared to the test year in the prior case. In other words, the deferral should be no greater than $5.240 million (($10.479 million divided by 2 to reflect the first six months of 2020).

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[50] Revised Direct Testimony of Christa Graft at 29.
[51] Schedule OM17.

Q. If the Commission authorizes recovery of an increase in vegetation management expense, is the Company required to increase vegetation management expense starting January 1, 2020?

A. No. If the Commission authorizes an increase in vegetation management expense, then the Company can expand the scope of its vegetation management activities and incur the additional expense starting on or about the date when the new base rates go into effect. The Company assumed that new base rates will go into effect on July 1, 2020 for purposes of calculating the regulatory assets balances used for annualized amortization expense in the test year.

Q. What is your recommendation?

A. I recommend that the Commission deny authorization for this regulatory asset. If, however, the Commission authorizes an increase in recovery, then the Company can and should delay the increases in activities and expense until the effective date when new base rates go into effect. In any event, even if the Commission authorizes an increase in recovery and allows the deferral to start January 1, 2020, it should be no greater than $5.240 million based on the proposed increase in the test year, not the increase over the amount in present base rates.

Q. What is the effect of your recommendation?

A. The effect is a $3.078 million reduction in total Company expense and a reduction of the revenue requirement by $3.083 million.[52]

III. OPERATING INCOME ISSUES

A. Unbilled Revenues

Q. Describe the Company's actual and forecast revenue accounting methodology.

A. The Company forecasts its *per books* test year revenues in the same manner that it records and reports revenues for financial reporting purposes. More specifically, the Company records and reports revenues using the so-called *unbilled* revenues methodology whereby it calculates revenues based on its actual sales each month even if a portion of those sales have not yet been billed (unbilled). Under the *unbilled* revenues methodology, the Company starts with the revenues actually billed during the month, subtracts the revenues billed in the current month for sales in the preceding month, and then adds the revenues for actual sales in the month that have not yet been billed. It repeats this pattern each month.

The *unbilled* revenues methodology results in revenue accruals that accurately reflect the Company's actual or forecast sales in the month at its authorized billing rates. In contrast, the *billed* revenues methodology is based on sales billed in the month. The billed revenues in a month primarily reflect sales in the prior month due to the lag in billing necessitated by monthly after the fact cycle meter reading and bill preparation. The billed revenues methodology results in

[52] MSFR Workpaper DA2-DLD.

revenue accruals that do not accurately reflect the Company's actual or forecast sales in the month at its authorized billing rates.

Q. Has the Company confirmed that it will record the actual changes in unbilled revenues in the test year as revenues on its accounting books?

A. Yes. In OUCC discovery, the Company was asked to "[c]onfirm that the actual changes in unbilled revenues in the test year will be recorded as revenues on the Company's books in the test year."[53] The Company responded: "Yes, the actual changes in unbilled revenues in the test year will be recorded as revenues on the Company's books in the test year."[54]

Q. Describe the Company's proposal to restate the forecast test year revenues to reflect a billed revenues methodology.

A. The Company proposes to reduce forecast *per books* test year retail revenues calculated using the unbilled revenues methodology by $28.853 million to restate those revenues using the billed revenues methodology. The Company made no argument in support of this adjustment except to simply assert that the unbilled revenues are "properly excluded" and that the revenue deficiency in a rate is case is based on "billed revenues only." Ms. Graft states this rationale as follows.

> Schedule REV3 removes $28,853,000 from Test Period revenues for unbilled revenues that are properly excluded from the development of new base rates. Unbilled revenues represent the estimated amount of revenues associated with electric utility service the Company has provided but not yet billed to

[53] OUCC 31.2(c).
[54] Response to OUCC 31.2(c). I have attached a copy of that response as my Exhibit___(LK-15).

customers. The Company bases the calculation of the revenue deficiency in a rate case on billed revenues only.[55]

Q. Are unbilled revenues "properly excluded" from the present revenues used to calculate the revenue deficiency?

A. No. It is inappropriate to understate revenues to reflect an outdated *billed* revenues accrual methodology that is not used by DEI or other utilities subject to generally accepted accounting principles ("GAAP") or the FERC Uniform System of Accounts ("USOA").

It is inappropriate to understate revenues to reflect sales in a period other than the test year. The Company's proposal results in a fundamental mismatch between the effective twelve months used to determine the revenues and the test year requested and approved in this proceeding. Under the Company's proposed billed revenues methodology, the revenues are understated because sales effectively run from some weighted date in December 2019 through some weighted date in December 2020 rather than from the forecast sales from January 1, 2020 through December 31, 2020, the test year in this case.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request to understate revenues using the billed revenues methodology. The Company's revenues should reflect the forecast sales in the year, not the billed sales, which lag the actual sales each month and should reflect the same unbilled revenues methodology that the

[55] Revised Direct Testimony of Christa Graft at 7.

Company uses for financial reporting. The billed revenues methodology understates the sales and revenues in the test year and creates a fundamental mismatch between the test year for revenues (approximately mid-December 2019 through mid-December 2020) compared to the approved 2020 calendar year test year used for the Company's costs (rate base, expenses, and capitalization).

B. Budgeting Error In O&M Expense Account 575 Market Monitoring And Compliance

Q. Describe the Company's budgeting error for account 575 market monitoring and compliance expense.

A. In discovery, the Company was asked to explain significant increases in test year expenses compared to the 2018 actual expenses for certain accounts, including account 575.[56] In the test year, the Company included $8.784 million in expense charged to this account. In 2018, it actually incurred $6.139 million in expense charged to this account. In other words, the Company forecast/budgets and seeks recovery of an additional $2.645 million in expense, or an increase of 43.1%, compared to 2018. As explanation for this significant increase in the test year, the Company responded: "2020 budget potentially overstated by $2M due to higher than trended budget for MISO Schedule 17."[57]

[56] OUCC 31.10.

[57] Response to OUCC 31.10, Attachment OUCC 31.10-A. I have attached a copy of that response as my Exhibit___(LK-16).

Q. What is your recommendation?

A. I recommend that the Commission correct this error and reduce the retail revenue requirement accordingly.

C. Incentive Compensation Expense Tied to Financial Performance

Q. Describe the Company's request for incentive compensation expense tied to *financial* performance metrics.

A. The Company included $28.655 million in total company incentive compensation expense, consisting of $12.401 million tied to the achievement of *financial performance* metrics by Duke Energy, Inc., the parent company of DEI and Duke Energy Business Services, LLC ("DEBS"), and $16.254 million tied to the achievement of *other* performance metrics. These amounts include the incentive compensation expense incurred directly by DEI related to its employees and expense incurred indirectly through charges from DEBS related to its employees.

Q. Provide a brief description of the incentive compensation plans that include compensation tied to the *financial* performance of Duke Energy, Inc.

A. Duke Energy, Inc. maintains three major incentive compensation programs, the Short Term Incentive Plan ("STI"), Union Employee Incentive Plan ("UEIP"), and Long Term Incentive Plan ("LTI"). Each plan is applicable to different defined employee groups, although there is some overlap, meaning that certain employees may participate in more than one plan. In addition, each plan has separate objectives, performance metrics, weightings of the performance metrics, and payout targets.[58]

Q. Describe the components of the STI that include compensation tied to the *financial* performance of Duke Energy, Inc.

A. The STI is applicable to executives and all other employees of DEI and DEBS; however, some employees participate in the UEIP sub-plan in accordance with their bargaining agreements. For executives, the earnings per share ("EPS") *financial* performance metric is weighted 50% and other performance metrics (O&M expense, *other* operational excellence, customer satisfaction, team goals, individual goals, and safety) are weighted 50% in the aggregate. For non-executive employees, the EPS *financial* performance metric is weighted 35% and *other* performance metrics are weighted 65% in the aggregate. If EPS is less than the target (100%) EPS *financial* performance metric, then the incentive compensation is reduced. If EPS is more than the target EPS *financial* performance metric, then the incentive compensation is increased.[59]

Q. Describe the components of the UEIP that include compensation tied to the *financial* performance of Duke Energy, Inc.

[58] Direct Testimony of Renee H. Metzler and Petitioner's Confidential Exhibits 18-E through 18-G (RHM).

[59] Petitioner's Confidential Exhibit 18-E (RHM). This exhibit provides the specific target performance metrics and ranges.

A. The UEIP is available to union employees of DEI and certain employees of other affiliated companies. Employees who participate in the UEIP are not eligible to participate in the STI otherwise available to executives and other exempt employees. The EPS financial performance metric is the same and is weighted the same as the EPS financial performance metric for the STI applicable to executives and other exempt employees.[60]

Q. Describe the components of the LTI that include compensation tied to the financial performance of Duke Energy, Inc.

A. Duke Energy has two LTI programs. One is an Executive LTI program called the Executive Incentive Plan ("EIP"). The EIP is reserved for members of the Enterprise Leadership Team ("ELT") and Senior Management Committee ("SMC") "to drive an ownership mindset and ensure accountability for making short- and long-term strategic decisions."[61] The other LTI program is available to other strategic leaders below the ELT level.[62]

The EIP "continues Duke Energy's focus on increased stock ownership, more direct alignment with shareholders and retention. Specifically, the plan: 1) provides for share ownership by executives; 2) delivers a portion of long-term incentive opportunity when value is delivered to shareholders; 3) provides for increased award

[60] *Id.*
[61] Direct Testimony of Renee Metzler at 26.
[62] *Id.*, 27.

value in alignment with increases in shareholder value; and 4) assists in the retention of key executive talent.[63]

The EIP provides an "incentive opportunity" based on a percentage of an executive's base compensation tied to the achievement of financial performance metrics. For example, the Duke Energy CEO has an "incentive opportunity" equivalent to 750% of her base compensation. The EIP incentive compensation is paid out 70% in the form of performance shares and 30% in the form of restricted stock units. The 70% in performance shares is based on EPS (50% weighting) and TSR (25% weighting) financial performance metrics and a total incident (25% weighting) other performance metric. The 30% in restricted stock units vests over a three year period and includes dividends on the restricted stock units.

The other LTI program also provides an "incentive opportunity" based on an employee's base compensation and is paid out in the form of restricted stock units. This incentive compensation vests over a three year period and includes dividends on the restricted stock units.

Q. Should the incentive compensation expense tied to Duke Energy *financial* performance be included in the revenue requirement?

A. No. The foundational ratemaking issue is not whether Duke Energy, and more specifically, DEI, incurs incentive compensation expense tied to its parent company's *financial* performance, but whether DEI customers should reimburse DEI for this portion of incentive compensation expense through their rates. That

[63] Petitioner's Confidential Exhibit 18-G (FHM).

ratemaking determination depends on whether the incentive compensation expense ultimately is incurred to incentivize performance that benefits DEI customers, not harms them, or whether it is incurred to incentivize performance that benefits Duke Energy shareholders.

The achievement of Duke Energy EPS and TSR *financial* performance metrics exclusively benefit Duke Energy shareholders. Achievement of these metrics does not benefit DEI customers. Nor does the incentive compensation expense incurred to incentive and reward the achievement of these *financial* performance metrics benefit DEI customers.

On the other hand, other operational and cost performance metrics arguably benefit shareholders and DEI customers to varying degrees and thus, the incentive compensation expense incurred to incentivize and reward the achievement of these other performance metrics at least has the potential to benefit DEI customers.

The Kentucky Public Service Commission ("KPSC") does not allow recovery of incentive compensation expense tied to *financial* performance as a general policy. In recent Duke Energy Kentucky electric and gas rate cases, the KPSC has affirmed this general policy. The KPSC has found that "Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures."[64]

Q. Are there other reasons not to allow recovery of incentive compensation expense tied to *financial* performance metrics from customers?

A. Yes. First, incentive compensation incurred to incentivize Duke Energy *financial* performance provides the Company's executives, managers, and employees a direct incentive to seek greater rate increases from customers, whether in the form of base rate increases or rider increases, in order to improve its parent company's EPS and TSR. The greater the rate increases and revenues, the greater Duke Energy's EPS and TSR and the greater the incentive compensation expense. In essence, the incentive compensation could be characterized as a "success fee" for successfully increasing customer rates. Thus, there is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater incentive compensation for executives, managers, and other employees on the other hand. All such expenses should be allocated to Duke Energy shareholders, not to DEI's customers.

Second, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues result in greater EPS and TSR. The additional revenues ensure that the expense is covered regardless of the Company's actual performance and regardless of its operational and safety

[64] Order in Atmos Energy Corporation KPSC Case No. 2013-00148 at 9.

performance. Thus, the expenses should be directly assigned to Duke Energy shareholders, not to DEI's customers.

Third, the Duke Energy EPS is significantly affected by the financial performance of other Duke Energy affiliates, including both regulated utility and unregulated affiliate earnings, and the Duke Energy TSR is significantly affected by the performance of other Duke Energy affiliates and the financial performance of other unrelated utility holding companies. The DEI customers should not subsidize the costs incurred by other Duke Energy affiliates' earnings or reward Duke Energy for its performance compared to other utility holding companies.

Fourth, Duke Energy and DEI determine compensation expense and the form of compensation regardless of ratemaking recovery. In my experience, there are numerous utilities that incur incentive compensation expense tied to *financial* performance despite disallowance of the expense for ratemaking purposes. That is certainly the case for Duke Energy Kentucky, a real world case study that demonstrates Duke Energy has not and apparently will not change its incentive compensation tied to *financial* performance based on ratemaking recovery.

Q. What is the effect of your recommendation?

A. The effect is a total Company \$12.951 million reduction in expense, consisting of a \$12.401 million reduction in incentive compensation expense and another \$0.550 million reduction in the related payroll tax expense. The effect is a \$12.309 million reduction in the revenue requirement, consisting of an \$11.786 million reduction for the reduction in incentive compensation expense and another $0.523 million for the reduction in the related payroll tax expense.

D. Quantification Of Change In Depreciation Expense To Reflect Depreciation Rate Recommendations Addressed by OUCC Witness Mr. Garrett In His Direct Testimony

Q. Have you quantified the change in depreciation expense to reflect the depreciation rate recommendations addressed by OUCC witness Mr. Garrett in his Direct Testimony?

A. Yes. The effect is a reduction of $109.260 million in depreciation expense on a total Company basis. I quantified the effect using the Company's plant in service amounts, as adjusted for OUCC recommendations. The revenue requirement effect is a reduction of $103.569 million.

E. Reduction in Indiana State Corporate Income Tax Rates and Expense

Q. Describe the Company's calculation of Indiana state income tax expense.

A. The Company calculated Indiana state income tax expense in three separate calculations, one for current income tax expense at present rates, one for deferred income tax expense, and another for the revenue conversion factor to calculate the gross up on the operating income deficiency to calculate the revenue deficiency and requested rate increase.

The Company used a blended test year state income tax rate of 5.375% for the current income tax expense. It used the 4.90% income tax rate effective July 1, 2021 for the deferred income tax expense. It used the 5.375% rate for the revenue conversion factor.

Q. Do you agree with the Company's use of the 4.90% income tax rate for the calculation of deferred income tax expense?

A. Yes. This is consistent with the Indiana income tax rate that will go into effect on July 1, 2021.

Q. Do you agree with the Company's use of the 5.375% income tax rate for the calculation of current income tax expense and the gross revenue conversion factor?

A. No. The Indiana state income tax rate will continue to phase-down from 5.5% (July 1, 2019 – June 30, 2020) to 5.25% (July 1, 2020 through June 30, 2021), and then to 4.90% on July 1, 2021, only six months after the end of the test year. However, the Company's base rates will not be reduced to match this reduction in current income tax expense until the next time base rates are reset. Consequently, the Company will overrecover current income tax expense unless the Commission addresses this issue in this proceeding.

Q. What are the alternatives for the Commission to consider?

A. The Commission could set base rates using an Indiana state income tax rate of 4.90% in this proceeding and in the gross revenue conversion factor and then allow the company to temporarily recover the differentials as the income tax rate phases down through the Credits Rider (as an offset to the credits in the rider) from the date new base rates go into effect in 2020 through June 30, 2021. Alternatively, the Commission could set base rates using the Indiana state income tax rate of 5.375% effective in the test year for current income tax expense and the gross revenue conversion factor and then require the Company to reflect the differential in the revenue requirement as a credit in the Credits Rider starting on July 1, 2021 and continuing until base rates are again reset.

Q. What is your recommendation?

A. I recommend the first alternative simply because the higher Indiana state income tax rate is only temporary and base rates may be in effect for an extended period of time before they are again reset. The first alternative will allow a "permanent" reduction in the base revenue requirement and require only a "temporary" increase in rates through the Credits Rider.

Q. What is the effect of your recommendation?

A. The effect is a $2.026 million reduction in the retail base revenue requirement, which initially will be exactly offset by an equivalent increase in the Credits Rider revenue requirement. Of course, that increase in the Credits Rider revenue requirement will phase out completely in July 2021, effectively implementing a $2.026 million rate reduction at that time. I have calculated this reduction in the retail base revenue requirement in two steps. The first step is a reduction in the current income tax expense at present rates calculated by the Company to reflect the 4.90% Indiana state income tax rate. The second step is to reflect a reduction in the current income tax expense at the proposed rates calculated using the gross revenue conversion factor.

F. Amortization Of Duke Energy Business Services EADIT As A One-Time Credit In The Credits Rider

Q. Describe the DEBS charges to the Company for income tax expense.

A. DEBS charges the Company and other affiliate companies a return on its "rate base" costs pursuant to the Service Company Utility Service Agreement.[65] The equity component of the return is grossed-up for income tax expense.[66] DEI witness Mr. Setser describes the "return" and "taxes" as follows.

> "Cost", as used in the Service Company Utility Service Agreement and Non-Utility Service Agreement, means fully embedded cost, which is the sum of: (1) direct costs; (2) indirect costs; and (3) cost of capital . . . Indirect costs include, but are not limited to, overhead costs, administrative support costs, and taxes. Cost of capital represents financing costs, including, but not limited to, interest on debt and a fair return on equity to shareholders.[67]

DEBS records both current income tax expense on its taxable income and deferred income tax expense on temporary differences used to calculate its current income tax expense. It then accumulates the deferred income tax expense as accumulated deferred income taxes ("ADIT").

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[65] Direct Testimony of Jeffrey Setser at 9-10 and Exhibit 16-A.

[66] Duke Energy Kentucky's response to AG-DR-02-027 in Case No. 2017-00321 before the Kentucky Public Service Commission states in part: "The Service Company charges a return for the use of DEBS assets to the jurisdictions. This represents a cost of capital for assets on the Service Company that are used in the operations of Duke Energy and its subsidiary companies. For 2016 the return on DEBS assets was $47.86 million, income tax expense was $20.94 [million], resulting in net income of $26.9 million. For 2015 the return on DEBS assets was $39.71 [million], income tax expense was $18.45 [million], resulting in net income of $21.3 million. The income statement for DEBS would have been close to zero, except for the return on assets and income tax expense." I have attached a copy of that response as my Exhibit___(LK-17).

[67] Direct Testimony of Jeffrey Setser at 15.

Q. How did the Tax Cuts and Jobs Act affect the ADIT recorded on DEBS accounting books?

A. Before the TCJA was enacted, DEBS recorded the federal ADIT on its accounting books at the federal income tax rate of 35%. When the TCJA was enacted in late 2017, DEBS remeasured the ADIT at the new federal income tax rate of 21%. DEBS did not retain the EADIT on its accounting books, but instead recorded the EDIT as a reduction to deferred income tax expense in 2017.[68] In other words, DEBS took the EDIT to income in 2017.[69]

Q. Did DEBS refund the EADIT to the Company and its other affiliate companies?

A. No. DEBS unilaterally recorded the EDIT as an increase to income in 2017.

Q. Was it just and reasonable for DEBS to take the EADIT to income in 2017 instead of refunding the EDIT to the Company and other affiliate companies?

A. No. This unilateral action was particularly egregious given that DEBS collected the ADIT at the federal income tax rate of 35% from the Company and other affiliate companies in prior years. As a service company, DEBS should have refunded the EADIT to the Company and other regulated utility affiliate companies so that they could refund these amounts to their customers.

[68] Response to OUCC 20.6. I have attached a copy of that response as my Exhibit___(LK-18).

[69] *Id.* The Company stated that "DEBS remeasured its ADIT based on the new federal corporate income tax rate of 21% and removed the excess ADIT through the income statement."

DEBS should have refunded the EADIT to the Company and other regulated utility affiliate companies even if it had not charged them for income tax expense at the federal income tax rate of 35%. The Company recovers charges from DEBS in the same manner as if it had incurred the costs itself. DEBS acquired assets and depreciated those assets for book and income tax purposes. DEBS used bonus and MACRS accelerated depreciation for income tax purposes, which created temporary differences and the resulting ADIT for the bonus and accelerated tax depreciation in excess of straight line depreciation. DEBS charged the Company and other affiliate companies for the depreciation expense on these assets and is entitled to any tax benefits, including the EADIT.

Q. What is your recommendation?

A. I recommend that the DEBS EADIT be allocated to the Company in the same manner that DEBS depreciation expense is allocated to the Company and then refunded to the Company's customers as a one-time credit through the Credits Rider.

Q. What is the effect of your recommendation?

A. The effect is a $2.910 million one-time refund through the Credits Rider. The effect on the revenue requirement is the retail jurisdictional effect of the EADIT grossed-up for income taxes. The total DEBS EADIT at December 31, 2017 was $21.725 million.[70] DEI would have been allocated $2.277 million of this amount if DEBS

[70] Response to OUCC 20.6; sum of DEBS entries to accounts 190, 282, and 283.

had not retained the EADIT and recorded it to income in 2017.[71] It is necessary to gross-up the DEBS EADIT to a revenue equivalent in the same manner that the Company's EADIT was grossed-up to a revenue requirement equivalent for refund purposes.

IV. QUANTIFICATION OF COST OF CAPITAL ISSUES

A. Accumulated Deferred Income Taxes Included In Capitalization As Cost-Free Capital

1. ADIT Related To OUCC Rate Base Adjustments

Q. Describe the ADIT included in the capitalization as cost-free capital.

A. The Company included the forecast ADIT in capitalization as cost-free capital. It provided a schedule showing the per books and proforma forecast ADIT by temporary difference at December 31, 2020.[72]

Q. Are there ADIT adjustments that are necessary due to the OUCC rate base adjustments?

A. Yes. Each OUCC rate base adjustment has a related ADIT effect, except for the adjustments to fuel and materials and supplies inventories.

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[71] Response to OUCC 20.5. The DEBS allocation factor used to allocate/charge depreciation expense for DEBS' assets to DEI is 10.48%. I have attached a copy of that response as my Exhibit___(LK-19).

[72] WPTX7-DLD after proforma adjustments. Response to OUCC 8.20, Attachment 8.20-A per books. I have duplicated this multipage attachment as part of my electronic workpapers filed along with my Direct Testimony.

Q. What is the effect of these adjustments to ADIT?

A. The effect is an $8.319 million increase in the retail revenue requirement due to the reduction in ADIT included in capitalization as cost-fee capital.

2. Certain ADIT Amounts Incorrectly Subtracted from ADIT Included In Capitalization As Cost-Free Capital

Q. Did the Company understate the ADIT included in capitalization as cost-free capital by failing to exclude certain per books ADIT amounts?

A. Yes. The Company failed to remove certain per books ADIT amounts through proforma adjustments for ratemaking purposes. As a general ratemaking principle, the ADIT reflected in capitalization as cost-free capital should match the rate base or other ratemaking treatment for the underlying temporary difference that gave rise to the ADIT. More specifically, if the underlying temporary difference is not reflected as an addition to or subtraction from rate base, then the related liability or asset ADIT should not be added to or subtracted from the ADIT included in capitalization. For example, if a rate refund accrual is not subtracted from rate base, then the related asset ADIT should not be subtracted from the ADIT included in capitalization.

In addition, if the underlying expense or other temporary difference is not included in operating income, then the related ADIT should not be added to or subtracted from the ADIT included in capitalization. For example, if supplemental executive retirement plan ("SERP") expense is not allowed as an operating expense, then the related asset ADIT should not be subtracted from the ADIT included in capitalization.

Q. What are the ADIT amounts that understate (on a net basis) the ADIT included in capitalization?

A. The ADIT amounts that incorrectly reduce (on a net basis) the ADIT included in capitalization are shown on the following table, along with the reason why it should not be included in rate base. The positive amounts shown on the table are asset ADIT that incorrectly reduced the ADIT included in capitalization and the negative amounts are the liability ADIT that incorrectly increased the ADIT included in capitalization. I have summed the effects on the retail revenue requirement of removing these ADIT amounts from the ADIT included in capitalization and shown the effect on a single line item on the table in the Summary section of my testimony.

Duke Energy Indiana, LLC
OUCC Recommended ADIT Adjustments
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	Federal ADIT	State ADIT	Total ADIT	Reason*
FIT Gross-Up on Excess Federal Tax	5,130,584	-	5,130,584	3
FIT Gross-Up on Excess Federal Tax	1,576,799	-	1,576,799	3
Bad Debts - Tax over Book	431,923	105,975	537,898	2
Surplus Materials Write-off Liab	5,036	1,236	6,272	2
Surplus Materials Write-Off Asset	71,942	17,651	89,593	2
LT Cap Lease Oblig-Tax Oper	1,934,889	474,736	2,409,625	2
Mark to Market - LT	4,192,548	1,028,666	5,221,214	2
Accrued Vacation	3,586,550	879,981	4,466,531	2
Property Tax Reserves	3,690,477	905,480	4,595,957	2
Severence Reserve - LT	495,709	121,625	617,334	2
MGP Sites	768,883	188,650	957,533	2
Deferred Revenue	508,123	124,671	632,794	2
Miscellaneous NC Taxable Income Adj - DTA	2,667,840	654,570	3,322,410	2
Reserve for Claims	813,818	199,675	1,013,493	2
Lawsuit Contingency	841,006	206,346	1,047,352	2
Rate Refunds	(218,931)	(53,716)	(272,647)	2
Demand Side Management (DSM) Defer	1,538,861	377,568	1,916,429	2
Charitable Contribution Carryover	43,683	10,718	54,401	1
Retirement Plan Expense - Underfunded	7,793,009	1,912,059	9,705,068	2
Non-qualified Pension - Accrual	637,311	156,368	793,679	2
RUS Obligation - Contract Reserve	10,407,789	2,553,611	12,961,400	3
Annual Incentive Plan Comp	1,445,266	354,604	1,799,870	1
OPEB Expense Accrual	11,407,830	2,798,977	14,206,807	1,2
FAS 112 Medical Expenses Accrual	1,058,173	259,629	1,317,802	1,2
OPEB Admin Fees	(1,094,679)	(268,586)	(1,363,265)	2
Deferral Comp - Emp Director	665,412	163,263	828,675	1
FERC - FIT Adj Offset to Regulatory Liability (182320)	59,002,419	-	59,002,419	2
FERC - SIT Adj Offset to Regulatory Liability (182320)	-	29,034,613	29,034,613	2
Reg Liability - Overcollection of Revenue Refund Adj	(3,530,980)	(866,346)	(4,397,326)	2
Vacation Carryover - Reg Asset	(2,205,370)	(541,100)	(2,746,470)	2
Deferred Fuel Asset - LT	(2,864,025)	(702,705)	(3,566,730)	2
Rate Case - Deferred Costs	(83,007)	(20,366)	(103,373)	2
Federal Excess DIT Adjustment-254036	27,121,792	-	27,121,792	3
Total	137,840,680	40,077,853	177,918,533	

* 1: Expense not included in revenue requirement
2: Temporary difference not added to or subtracted from rate base
3: Temporary difference not included in cost of capital

Q. What is the effect of these adjustments to ADIT?

A. The effect is a $10.559 million reduction in the retail revenue requirement due to the increase in ADIT included in capitalization as cost-fee capital.

B. Quantification of Cost of Long-Term Debt Recommendation Addressed by Mr. Garrett

Q. Have you quantified the effect of Mr. Garrett's cost of long-term debt recommendation?

A. Yes. I quantified an incremental $7.687 million reduction in the Company's claimed revenue requirement and requested increase. I calculated the reduction in the grossed-up cost of capital using Mr. Garrett's recommendations compared to the Company's requested cost of capital, both of which reflect the equity return grossed-up based on the OUCC recommendation to use an Indiana state income tax rate of 4.90% and the OUCC ADIT recommendations. I then applied this reduction in the grossed-up cost of capital to the Company's rate base, as adjusted to reflect the OUCC rate base recommendations.

C. Quantification of Return On Equity Recommendation Addressed by Mr. Garrett

Q. Have you quantified the effect of the return on equity recommended by Mr. Garrett instead of the return on equity reflected in the Company's filing?

A. Yes. I quantified an incremental $74.209 million reduction in the Company's claimed revenue requirement and requested increase. I calculated the reduction in the grossed-up cost of capital compared to the grossed-up cost of capital after the prior adjustments, including the OUCC Indiana state income tax rate and ADIT recommendations, and cost of long-term debt. I then applied this incremental reduction in the grossed-up cost of capital to the Company's rate base as adjusted to reflect the OUCC rate base recommendations.

D. Quantification of Each 10 Basis Points In The Return On Equity

Q. Have you quantified the effect of each 10 basis points in the return on equity?

A. Yes. Each 10 basis points in the return on equity equals $5.301 million in the revenue requirement and requested increase. This effect reflects the OUCC rate base recommendations and the OUCC ADIT included in capitalization recommendations.

E. Overall Cost of Capital

Q. What is the overall cost of capital including all OUCC recommendations compared to the Company's request?

A. The following table compares the capital structure, costs of each component, and the overall cost of capital requested by the recommended by OUCC compared to the Company's request.

Duke Energy Indiana, LLC
Cost of Capital
IURC Cause No. 45253

DEI Cost of Capital Per Filing

	Capital Amount	Capital Structure Ratio: Financial Ratio	Capital Structure Ratio: Regulatory Ratio	Component Costs	Weighted Cost Ratio: Financial Weighted Avg Cost	Weighted Cost Ratio: Regulatory Weighted Avg Cost
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%	0.00%
Long Term Debt	4,224.223	46.96%	36.35%	4.88%	2.29%	1.77%
Preferred Stock	-	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	4,770.344	53.04%	41.05%	10.40%	5.52%	4.27%
Total Financial Capitalization	8,994.567	100.00%	77.40%		7.81%	6.04%
Deferred Income Taxes including Excess Deferred Taxes	2,433.783		20.94%	0.00%		0.00%
Unamortized ITC - Crane Solar	10.999		0.09%	7.81%		0.01%
Unamortized ITC - 1971 & Later	1.955		0.02%	7.81%		0.00%
Unamortized ITC - Advanced Coal (IGCC)	133.500		1.15%	7.81%		0.09%
Customer Deposits	47.056		0.40%	2.00%		0.01%
Total Capital	11,621.860		100.00%			6.15%

DEI Cost of Capital Recommended by OUCC

	Capital Amount	Capital Structure Ratio: Financial Ratio	Capital Structure Ratio: Regulatory Ratio	Component Costs	Weighted Cost Ratio: Financial Weighted Avg Cost	Weighted Cost Ratio: Regulatory Weighted Avg Cost
Short Term Debt	-	0.00%	0.00%	0.00%	0.00%	0.00%
Long Term Debt	4,224.223	46.96%	36.21%	4.66%	2.19%	1.69%
Preferred Stock	-	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	4,770.344	53.04%	40.89%	9.00%	4.77%	3.68%
Total Financial Capitalization	8,994.567	100.00%	77.10%		6.96%	5.37%
Deferred Income Taxes including Excess Deferred Taxes	2,478.006		21.25%	0.00%		0.00%
Unamortized ITC - Crane Solar	10.999		0.09%	6.96%		0.01%
Unamortized ITC - 1971 & Later	1.955		0.02%	6.96%		0.00%
Unamortized ITC - Advanced Coal (IGCC)	133.500		1.14%	6.96%		0.08%
Customer Deposits	47.056		0.40%	2.00%		0.01%
Total Capital	11,666.083		100.00%			5.47%

V. IGCC RIDER (CONTRACT 61)

Q. Describe the Company's request to terminate the IGCC Rider and roll-in the IGCC revenue requirement to the base revenue requirement.

A. The Company seeks to terminate the IGCC Rider and roll-in the IGCC revenue requirement to the base revenue requirement for the test year when base rates are reset in this proceeding.[73]

Q. What are the effects of terminating the IGCC Rider?

A. The Company's request results in a greater revenue requirement in the test year and in subsequent years. This occurs for multiple reasons. The first reason is that the Company seeks to include costs in the base revenue requirement that it could not include in the IGCC Rider, including, but not limited to the fuel and materials and supplies inventories in rate base. Mr. Alvarez addresses the fuel and materials and supplies inventories in rate base.

The second reason is that the base revenue requirement will not decline as the IGCC cost curve declines due to additional accumulated depreciation (reduction to rate base) and additional ADIT (increase in cost-free capital included in capitalization) until the Company's next base rate case and base rates are again reset in that proceeding.

Q. Is the IGCC the plant-related cost sufficiently significant that the Commission should continue to track the declining cost curve after December 31, 2020?

A. Yes. The IGCC is the Company's single largest asset representing approximately 20% of the Company's rate base.

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[73] Revised Direct Testimony of Diana Douglas at 68-69.

Q. What is your recommendation?

A. I recommend that the Commission reflect the reduction in the IGCC plant-related revenue requirement (grossed-up return on the increase in accumulated depreciation and the reduction in the grossed-up cost of capital due to the increase in ADIT) in either the ECR Rider or the Credits Rider.[74] This will maintain the existing benefit to customers of the declining IGCC cost curve that otherwise will be lost under the Company's proposal to roll-in and fix the base rate recovery until the Company's next base rate case and base rates are again reset in that proceeding.

VI. CREDITS RIDER (CONTRACT 67)

Q. Summarize your recommendations to modify the Credits Rider (Contract 67) consistent with your recommendations to reflect the post-test year reductions in the Edwardsport IGCC revenue requirement, recovery of regulatory assets, reductions in the Indiana state corporate income tax rate, and reductions in Gallagher 2 and 4 non-fuel O&M expense when those generating units are retired in 2022.

A. I recommend that the Commission modify the Credits Rider to reflect the reductions in the revenue requirement as the Edwardsport test year rate base declines due to additional accumulated depreciation and as the cost of capital declines due to

[74] Revised Direct Testimony of Diana Douglas at 70-76. The Company proposes that certain IGCC amounts be reconciled through the ECR Rider and that certain tax benefits be refunded and reconciled through the Credits Rider.

additional ADIT. I do not recommend that the Commission offset these reductions with post-test year increases in plant in service.

I recommend that the Commission modify the Credits Rider to reflect the reductions in the revenue requirement as regulatory assets are amortized. This includes the reduction in the return on the regulatory assets included in rate base and the cessation of amortization expense after the regulatory assets are fully amortized.

In addition, I recommend that the Commission modify the Credits Rider to reflect the reductions in the Indiana state corporate income tax rate to 4.90% on July 1, 2021 and the effects on the current income tax expense in the base revenue requirement. Under my primary recommendation to use the 4.90% rate in the base revenue requirement, the Company would be allowed to recover the incremental current income tax expense prior to that date through the Credits Rider (effectively as a surcharge). This would be a temporary short-term surcharge through the Credits Rider and would expire on June 30, 2021. Under my alternative recommendation to use the 5.375% blended rate reflected in the Company's filing in the base revenue requirement, the Company would be required to provide a credit through the Credits Rider as the rate declines. This credit would continue until base rates are reset to reflect the 4.90% rate in the base revenue requirement.

Finally, I recommend that the Commission modify the Credits Rider to reflect the reductions in the Gallagher 2 and 4 non-fuel O&M expense when those generating units are retired in 2022.

Q. Does this complete your testimony?

A. Yes.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**)**	**CAUSE NO. 45253**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

OCTOBER 30, 2019

EXHIBIT _____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company’s Service Territory
Cities in AEP Texas Central Company’s Service Territory
Cities in AEP Texas North Company’s Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General’s Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.

Expert Testimony Appearances
of
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As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
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As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.

Expert Testimony Appearances
of
Lane Kollen
As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8469	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.

Expert Testimony Appearances
of
Lane Kollen
As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.

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9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.

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7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.

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11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.

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10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.

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09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.

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03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.

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02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.

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05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.

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03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.

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09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.

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04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.

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09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.

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04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.

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11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Rebuttal Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.

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11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

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12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.

Expert Testimony Appearances
of
Lane Kollen
As of October 2019

Date	Case	Jurisdict.	Party	Utility	Subject
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.

**Expert Testimony Appearances
of
Lane Kollen
As of October 2019**

Date	Case	Jurisdict.	Party	Utility	Subject
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 03/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.

**Expert Testimony Appearances
of
Lane Kollen
As of October 2019**

Date	Case	Jurisdict.	Party	Utility	Subject
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Next Era acquisition of Oncor; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.
08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.

**Expert Testimony Appearances
of
Lane Kollen
As of October 2019**

Date	Case	Jurisdict.	Party	Utility	Subject
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky (Electric)	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.
09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.

**Expert Testimony Appearances
of
Lane Kollen
As of October 2019**

Date	Case	Jurisdict.	Party	Utility	Subject
01/19	2018-00281	KY	Attorney General	Atmos Energy Group	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-17 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-0358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.
10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.

EXHIBIT ____ (LK-2)

DUKE ENERGY INDIANA, LLC
RETAIL ELECTRIC RATE CASE BEFORE THE IURC
Forward-Looking Test Period: Twelve months ending December 31, 2020
Historical Base Period: Twelve months ending December 31, 2018

170 IAC	Description
1-5-12(2)(C)	When determining the pro forma fuel inventory level to be used for regulatory purposes based on a daily burn concept, for each generating unit or plant, or both, provide the following: (i) Tons of fuel consumed for the test year or applicable adjusted period (ii) The daily burn in (AA) tons, (BB) gallons, or (CC) cubic feet (iii) The pro forma optimal number of days supply required for each plant or unit (iv) The pro forma inventory of tons or gallons burned by the generating unit or plant (v) The fuel cost per ton or gallon (vi) The per books fuel inventory

Forward-Looking Test Period and Historical Base Period:

Please see 1-5-12(2)(C)(i) Att. 1 for daily tons of fuel consumed by plant for the historical base period and for the forward-looking test period. Please see 1-5-12(2)(C)(ii-vi) Att. 2 for the per books and forecasted inventory quantities (tons and days) and dollars for burn by generating plant, as well as the associated number of days.

DUKE ENERGY INDIANA, LLC
Fuel Consumed for Historical Base Period and Forward-looking Test Period

		Historical Base Period (2018)			Forward-Looking Test Period (2020)			
Line No.	Station	Tons of Coal_1/	Gallons of Fuel Oil	Mcfs Natural Gas	Tons of Coal	Gallons of Fuel Oil_2/	Mcfs Natural Gas	Line No.
1	Cayuga	2,725,533	320,861	-	1,973,592	-	-	1
2	Cayuga Unit 3 - IC	-	23,710	-	-	-	-	2
3	Edwardsport IGCC - Coal	1,443,324	0	-	1,597,791	-	-	3
4	Gallagher	143,754	2,015,514	-	365	-	-	4
5	Gibson	8,228,541	2,716,790	-	6,775,090	-	-	5
6	Gibson Unit 5 JO Share	(793,520)	(228,465)	-	-	-	-	6
7	Cayuga Unit 4 - CT	-	-	2,916	-	-	155,481	7
8	Madison - CT	-	-	7,114,818	-	-	2,429,740	8
9	Henry County - CT	-	-	2,932,704	-	-	2,755,975	9
10	Noblesville - CT	-	-	11,956,959	-	-	16,273,328	10
11	Wheatland - CT	-	-	2,491,380	-	-	5,640,117	11
12	Edwardsport IGCC - NG	-	-	10,646,715	-	-	732,000	12
13	Vermillion - CT	-	-	3,088,372	-	-	2,429,423	13
14	Vermillion - CT JO Share	-	-	(1,158,139)	-	-	-	14
15	Total	11,747,632	4,848,410	37,075,725	10,346,838	-	30,416,064	15

_1/ Includes any year-end tons adjustment related to the results of the annual aerial coal pile survey.

_2/ Fuel Oil not forecasted for forward-looking test period of 2020.

Duke Energy Indiana, LLC
Response to 1-5-12(2)(c)(ii):

For purposes of calculating the number of days of coal burn at each station, the Company uses the following full load burn amounts:

Station	Tons of Coal
Cayuga	10,750
Edwardsport	6,240
Gallagher	2,900
Gibson	34,500

Response to 1-5-12(2)(c)(iii)-(vi):

Line No.	Description	31-Dec-18 Balance (A)	2019 Activity (B)	31-Dec-19 Balance (A) + (B) = (C)	2020 Activity (D)	31-Dec-20 Balance (C) + (D) = (E)	31-Dec-20 Days Burn (F)	Cost/Ton (G)	Line No.
	0151130 Coal Stock ($ in thousands)								
1	Cayuga	$ 23,083	$ 4,468	$ 27,551	$ (53)	$ 27,498	47	[redacted]	1
2	Edwardsport	13,534	342	13,876	(219)	13,657	46	[redacted]	2
3	Gibson (DEI Share) _1/	65,006	12,144	77,150	(921)	76,229	43	[redacted]	3
4	Gallagher	5,921	(317)	5,604	(556)	5,048	31	[redacted]	4
5		107,544	16,637	124,181	(1,749)	122,432	-	[redacted]	5
6	0151131 Coal Stock in Transit	1,282	-	1,282	-	1,282	-	[redacted]	6
7	0151140 Diesel Fuel Stock	1,461	-	1,461	-	1,461	-	[redacted]	7
8	Total Fuel Inventory	$ 110,287	$ 16,637	$ 126,924	$ (1,749)	$ 125,175	-	[redacted]	8

_1/ Reflects DE Indiana portion of Gibson Unit 5, therefore may vary from reporting on 100% of Gibson station.

EXHIBIT ____ (LK-3)

OUCC
IURC Cause No. 45253
Data Request Set No. 31
Received: September 27, 2019

OUCC 31.5

Request:

Provide the accounts payable balances for fuel inventories at month-end for each month January 2018 through December 2018 (actuals), January 2019 through December 2019 (actuals for months where actual information is available and forecasts for remaining months), and January 2020 through December 2020 (forecasts).

Response:

See Attachment OUCC 31.5-A for the requested accounts payable balances for fuel inventory.

Witness: Suzanne E. Sieferman (actuals) / Christopher M. Jacobi (forecast)

Attachment OUCC 31.5-A

Duke Energy Indiana, LLC
Accounts Payable Fuel Inventories by Month
in dollars

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
A/P Coal (0232170)	$ 21,680,274	$ 21,336,738	$ 25,566,076	$ 20,986,480	$ 23,410,184	$ 19,165,315	$ 17,644,589	$ 16,080,122	$ 20,020,522	$ 18,500,573	$ 17,622,724	$ 18,073,913
A/P Oil Stocks (0232180)	$ 291,167	$ 45,523	$ -	$ 9,845	$ 154,436	$ 622,050	$ 51,254	$ 267,079	$ 309,843	$ 223,810	$ 555,917	$ 66,415
A/P Natural Gas (0232181)	$ 21,175,525	$ 6,272,340	$ 7,118,463	$ 13,013,307	$ 18,083,298	$ 10,991,522	$ 11,971,445	$ 11,777,911	$ 11,621,033	$ 10,771,797	$ 9,068,121	$ 5,560,282

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
A/P Coal (0232170)	$ 17,370,839	$ 15,968,838	$ 22,998,599	$ 16,914,199	$ 15,508,938	$ 16,650,392	$ 18,687,671	$ 12,299,775	$ 14,482,644	$ 14,353,775	$ 13,414,697	$ 5,851,602
A/P Oil Stocks (0232180)	$ 331,662	$ 374,834	$ 381,011	$ -	$ 143,010	$ 88,422	$ 14,179	$ -	$ 66,415	$ 66,415	$ 66,415	$ 66,415
A/P Natural Gas (0232181)	$ 14,612,076	$ 5,333,327	$ 7,840,187	$ 4,564,480	$ 4,160,090	$ 5,921,525	$ 8,375,999	$ 8,883,105	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282

	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
A/P Coal (0232170)	$ 21,387,553	$ 21,597,200	$ 15,436,464	$ 1,258,131	$ (1,431,481)	$ 5,226,879	$ 20,352,465	$ 17,772,832	$ (3,071,426)	$ (1,473,813)	$ (2,065,455)	$ 10,302,372
A/P Oil Stocks (0232180)	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415	$ 66,415
A/P Natural Gas (0232181)	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282	$ 5,560,282

EXHIBIT ____ (LK-4)

OUCC
IURC Cause No. 45253
Data Request Set No. 31
Received: September 27, 2019

OUCC 31.6

Request:

Provide the accounts payable balances for M&S inventories at month-end for each month January 2018 through December 2018 (actuals), January 2019 through December 2019 (actuals for months where actual information is available and forecasts for remaining months), and January 2020 through December 2020 (forecasts).

Response:

Actuals:

Period	Month End Balance
January 2018	$226,948.38
February 2018	$691,867.77
March 2018	$275,597.61
April 2018	$381,779.13
May 2018	$940,646.61
June 2018	$1,020,701.86
July 2018	$577,567.43
August 2018	$361,582.54
September 2018	$268,307.68
October 2018	$338,789.89
November 2018	$353,994.42
December 2018	$655,946.81
January 2019	$1,049,603.85
February 2019	$1,405,164.36
March 2019	$575,527.72
April 2019	$703,039.27
May 2019	$433,521.81
June 2019	$468,399.96
July 2019	$484,095.70
August 2019	$513,358.93

Forecasted:

Period	Month End Balance
September 2019	$513,358.93
October 2019	$513,358.93
November 2019	$513,358.93
December 2019	($486,641.07)
January 2020	$513,358.93
February 2020	$513,358.93
March 2020	$513,358.93
April 2020	$513,358.93
May 2020	$513,358.93
June 2020	$513,358.93
July 2020	$513,358.93
August 2020	$513,358.93
September 2020	$513,358.93
October 2020	$513,358.93
November 2020	$513,358.93
December 2020	($2,486,641.07)

Witness: Christopher M. Jacobi

EXHIBIT ____ (LK-5)

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Indiana, Inc	End of 2006/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Available Credit Facilities and Restrictive Debt Covenants. Duke Energy Indiana receives support for its short-term borrowing needs from its parent entity, Cinergy, whose short-term borrowings consist primarily of unsecured revolving lines of credit and sale of commercial paper. During June 2006, Cinergy and its subsidiaries, including Duke Energy Indiana, amended their multi-year syndicated $2 billion revolving credit facility to extend the expiration date from September 2010 to June 2011, to reduce costs, and to conform the terms to those found in the legacy Duke Energy facilities. In November 2006, the credit facility was decreased from $2.0 billion to $1.5 billion. This credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year and contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%. The credit facility also contains a $500 million borrowing sub limit for Duke Energy Indiana.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the available credit facilities.

Cinergy's credit agreement contains various financial and other covenants; however, Cinergy's credit agreement does not include material adverse change clauses or any covenants based on credit ratings. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2006, Cinergy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

5. Employee Benefit Obligations

Cinergy Retirement Plans. Duke Energy Indiana participates in qualified and non-qualified defined benefit pension plans as well as other post-retirement benefit plans sponsored by Cinergy. Cinergy allocates pension and other post-retirement obligations and costs related to these plans to Duke Energy Indiana.

Upon consummation of the merger with Duke Energy, Cinergy's benefit plan obligations were remeasured. Cinergy updated the assumptions used to determine their accrued benefit obligations and prospective net periodic benefit/post-retirement costs to be allocated to Duke Energy Indiana.

Duke Energy Indiana adopted the disclosure and recognition provisions of SFAS No. 158, effective December 31, 2006. The following table describes the total incremental effect of the adoption of SFAS No. 158 on individual line items in the Duke Energy Indiana December 31, 2006 Consolidated Balance Sheet.

	Duke Energy Indiana		
	Before Application of SFAS No. 158	**Adjustment**	**After Application of SFAS No. 158**
		(in millions)	
Accrued pension and other post-retirement liabilities [a]	$(172)	$ (276)	$ (448)
Regulatory Assets	---	276	276
Total Recognized	$(172)	$ ---	$ (172)

(a) Includes approximately $15 million reflected in Other Current Liabilities on the Consolidated Balance Sheets at December 31, 2006 and includes approximately $8 million in Other liabilities related to other post-retirement benefits.

OUCC
IURC Cause No. 45253
Data Request Set No. 33
Received: September 27, 2019

OUCC 33.8

Request:

Please state whether Petitioner complies with SFAS 158. If no, please explain why not.

a) If yes, has Petitioner recorded Petitioner's funded position?

b) If yes, has Petitioner recorded a regulatory asset (liability) balance for the timing difference between the amount recorded as expense and the amount recovered from customers over time?

c) If Petitioner has recorded its funded position, please state the amount and to what account it is recorded.

d) If Petitioner has recorded a regulatory asset (liability), please state the amount, whether this is an asset or liability, and to what account it is recorded.

e) If Petitioner has recorded a regulatory asset (liability, does it include both amounts expensed and capitalized or only amounts expensed? Please explain.

f) Is the regulatory asset/liability balance for the timing difference a cumulative amount calculated from the time FAS #87 was adopted? Or is this only calculated from 2006 when FAS #158 was adopted?

g) Has the regulatory asset (liability) been included in Petitioner's forecasted rate base? Please explain why or why not.

Response:

Yes, Duke Energy Indiana complies with former standard SFAS 158, which has since been codified within Accounting Standards Codification (ASC) 715.

a) Yes, amounts for the "funded position", which is interpreted as Funded Status under ASC 715, have been recorded for the company's defined benefit plans.

b) Yes, regulatory assets/liabilities have been recorded for the company's defined benefit plans.

c) The following table provides the funded status account and amounts for the company's defined benefit plans as of December 31, 2018:

Account		Funded Status
0128716 - Prefunded Pension (major)	$	1,738,865
0128717 - Prefunded Pension		37,534,902
0228346 - Pension Liability - FAS 87		(45,740,843)
Total Qualifed Pension Plans	$	(6,467,076)
0242897 - NC Pension Liability - FAS 87	$	(342,122)
0253630 - Schm Exec Cash Bal Plan		(2,849,058)
Total Nonqualified Pension Plans	$	(3,191,180)
0242998 - Misc Liab - FAS 106	$	(370,384)
0228315 - Schm Opeb (Fas106)		(61,491,836)
Total OPEB Plans	$	(61,862,220)

d) The following table provides the regulatory asset or liability account and amounts for the company's defined benefit plans as of December 31, 2018:

Account		Amount
Regulatory Assets		
0182800 - Acc Pen Post Ret Pur Acct-Qual	$	42,118,426
0182318 - Other Reg Assets - Gen Acct (pension)		139,973,221
Total Qualifed Pension Plans	$	182,091,647
0182801 - Pension Post Retire P Acctg - FAS87 NQ		(430,026)
Total Nonqualified Pension Plans		(430,026)
0182802 - Pension Post Retire P Acctg - FAS 106	$	(5,019,720)
0182312 - Oprb FAS 106 - Medical		45,596,828 A
Total OPEB Plans	$	40,577,108
Regulatory Liabilities		
0254689 - Reg Liability - NQ (OPEB)	$	(67,053,506)
Total OPEB Plans	$	(67,053,506)
0253043 - OPEB - FAS106 Grantor Trust	$	5,481,343

A - Balance reclassified to account 0182802 in March 2019.

e) The amounts included in response to part d (above) reflect actuarial loss (gain) that has been deferred under ASC 715, the amortization of which is included as a component of pension or OPEB expense. Please see the response to OUCC 8.9, and specifically Attachment OUCC 8.9-A. Answering further, the Company began charging its amortization of all non-service cost components of pension and OPEB costs beginning January 1, 2018, to expense, for consistency with GAAP accounting that became effective then, and also as allowed for FERC accounting purposes.

f) The regulatory asset/liability balances are cumulative since the adoption of SFAS 87.

g) The regulatory assets listed in part d. that are associated with the Company's pension plan (accounts 0182800, 0182318, and 0182801) were included in rate base as part of the Company's prepaid pension costs asset, along with other pension asset and liability accounts. See MSFR 1-5-9(a)(1) Workpaper RB5-DLD. The regulatory assets and liabilities associated with OPEB were not included in rate base, along with the Grantor Trust OPEB asset, which is excluded from retail ratemaking in accordance with prior Settlement Agreements and Commission orders.

Witness: Diana L. Douglas

EXHIBIT ____ (LK-6)

FEDERAL ENERGY REGULATORY COMMISSION
Office of Enforcement
Washington, D.C. 20426

In Reply Refer To:
OE
Docket No. AI07-1-000
March 29, 2007

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, OIL PIPELINE COMPANIES AND CENTRALIZED SERVICE COMPANIES

Subject: Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards No. 158 (SFAS No. 158 or the Statement), Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans. This statement requires an employer to recognize the overfunded or underfunded status of a single-employer defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. SFAS No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position.

A defined benefit postretirement plan is one that defines an amount of postretirement benefit to be provided to retirees. Pension benefits are usually defined as a function of one or more factors such as age, years of service or compensation. Postretirement benefits other than pensions are usually defined in terms of (a) monetary amounts (for example, $100,000 of life insurance) or (b) benefit coverage to be provided (for example, up to $200 per day for hospitalization, 80 percent of the cost of specified surgical procedures). Postretirement benefits include, but are not limited to, pension benefits; postretirement health care; life insurance provided outside of a pension plan to retirees; and other welfare benefits such as tuition assistance, day care, legal services, and housing subsidies provided after retirement.

The Commission's Uniform Systems of Accounts for jurisdictional entities do not provide specific implementation guidance with regard to the accounting and reporting matters contained in SFAS No. 158.[1] The following guidance is being provided to all jurisdictional entities to ensure proper and consistent implementation of SFAS No. 158 for FERC financial reporting purposes beginning with the 2007 FERC Form Nos. 1, 1-F, 2, 2-A, 6, and 60 due to be filed in 2008. Earlier implementation is encouraged.

This guidance is for FERC financial accounting and reporting purposes only and is without prejudice to the ratemaking practice or treatment that should be afforded the items addressed herein.

1. ADOPTION OF SFAS NO. 158 FOR FERC ACCOUNTING AND REPORTING PURPOSES

Background: SFAS No. 158 provides guidance on recognition of the funded status of a single-employer defined benefit postretirement plan, measurement date of plan assets and benefit obligations, disclosure requirements, effective dates and transition provisions for its initial implementation. Some provisions allow employers certain choices in how to implement the Statement for stockholder reporting purposes. For example, paragraph numbers 12, 13, and 15 contain explicit effective dates but also encourage applying the Statement earlier than the explicit effective dates. Also, paragraph number 17 allows alternative approaches for an employer to transition to a fiscal year-end measurement date for plan assets and benefit obligations.

Question: Should jurisdictional entities adopt this Statement for reporting to the Commission and must it do so in the same manner as the Statement is adopted for stockholder reporting?

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[1] *See* 18 C.F.R. Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act* (2006); 18 C.F.R. Part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act* (2006); 18 C.F.R. Part 352, *Uniform System of Accounts Prescribed for the Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act* (2006); 18 C.F.R. § 366.22, *Accounts and records of service companies* (2006) and 18 C.F.R. Part 367, *Uniform System of Accounts for Centralized Service Companies Subject to the Provisions of the Public Utility Holding Company Act of 2005*, Order No. 684, issued October 19, 2006, *Financial Accounting, Reporting and Records Retention Requirements Under the Public Utility Holding Company Act of 2005*, FERC Stats. & Regs. ¶ 31,229 (2006).

Response: Yes, FERC jurisdictional entities should adopt SFAS No. 158 for reporting to the Commission and it should do so in the same manner as the Statement is adopted for stockholder reporting.

2. ACCOUNTS FOR RECORDING THE OVERFUNDED OR UNDERFUNDED STATUS OF POSTRETIREMENT DEFINED BENEFIT PLANS

Background: Paragraph number 4 of SFAS No. 158 requires an entity that presents a classified statement of financial position to classify the liability for an underfunded single-employer defined postretirement benefit plan as a current liability, noncurrent liability, or combination of both. The asset for an overfunded plan must be classified as a noncurrent asset in a classified statement of financial position.

Question 2A: What FERC accounts should jurisdictional entities use to record an asset for the overfunded status of one or more employee postretirement benefit plans?

Response: Public utilities and licensees, natural gas companies, oil pipeline companies and centralized service companies should use the accounts shown below to record assets for the overfunded status of their employees postretirement benefit plans. Separate subaccounts should be maintained for each postretirement benefit plan and overfunded plans should not be netted against underfunded plans, consistent with paragraph number 4 of SFAS No. 158.

Jurisdictional Entity	**FERC Accounts**
Public utilities and licensees (Major)	Account 129, Special funds
Public utilities and licensees (Nonmajor)	Account 128, Other special funds, or Account 129, Special funds
Natural gas companies	Account 128, Other special funds
Oil pipeline companies	Account 22, Sinking and other funds
Centralized service companies	
□ Periods prior to January 1, 2008	Account 124, Other investments, or Account 128, Other special funds
□ January 1, 2008 and subsequent periods	Account 128, Other special funds

Question 2B: What FERC accounts should jurisdictional entities use to record the liability for the underfunded status of one or more employee postretirement benefit plans?

Response: Public utilities and licensees, natural gas companies, oil pipeline companies and centralized service companies should use the accounts shown below to record liabilities for the underfunded status of their employee postretirement benefit plans. Separate subaccounts should be maintained for each postretirement benefit plan and underfunded plans should not be netted against overfunded plans, consistent with paragraph number 4 of SFAS No. 158.

Jurisdictional Entity	**FERC Accounts: Current Liability**	**FERC Accounts: Noncurrent Liability**
Public utilities and licensees (Major and Nonmajor)	Account 242, Miscellaneous current and accrued liabilities	Account 228.3, Accumulated provision for pensions and benefits
Natural gas companies	Account 242, Miscellaneous current and accrued liabilities	Account 228.3, Accumulated provision for pensions and benefits
Oil pipeline companies	Account 58, Other current liabilities	Account 63, Other noncurrent liabilities
Centralized service companies		
□ Periods prior to January 1, 2008	Account 242, Miscellaneous current and accrued liabilities	Account 253, Other deferred credits
□ January 1, 2008 and subsequent periods	Account 242, Miscellaneous current and accrued liabilities	Account 228.3, Accumulated provision for pensions and benefits

3. RECOGNITION OF RELATED REGULATORY ASSETS AND LIABILITIES

Background: An entity provides pension and other postretirement benefits to its employees under defined benefit plans and recognizes the related expense, *i.e.*, net periodic pension and other postretirement benefit costs, for financial accounting and reporting purposes in accordance with Statement of Financial Accounting Standards Nos.

87 (SFAS No. 87) and 106 (SFAS No. 106).[2] The rates the entity charges for services provided by a segment of its business are regulated by a third party regulator and are determined on the basis of the entity's costs. Development of the rates to be charged for services provided by this business segment include an allowance for postretirement benefits and the amount of that allowance is based on net periodic pension and other postretirement benefit costs determined in accordance with SFAS No. 87 and SFAS No. 106. The entity determines that it must recognize an asset for the overfunded status of its defined benefit pension plan and a liability for the underfunded status of its postretirement benefit plan other than pensions consistent with SFAS No. 158.

Question: At the time the entity recognizes its asset or liability to reflect the funded status of its postretirement benefit plans in accordance with SFAS No. 158, should it recognize a regulatory liability or asset for the amount of the funded status asset or liability otherwise includible in accumulated other comprehensive income related to its cost-based, rate-regulated business segment?

Response: Under SFAS No. 87 and SFAS No. 106, the cost of postretirement benefits provided to employees under a defined postretirement benefit plan are recognized as an expense at the time the employee provides related employment services.

Both SFAS No. 87 and SFAS No. 106 contain a delayed recognition feature. This means that certain changes in postretirement benefit obligations and the value of assets set aside to meet the obligations are not recognized when they occur but are recognized systematically and gradually over subsequent periods.[3] SFAS No. 158 is an amendment to SFAS No. 87 and SFAS No. 106, but it did not change the delayed recognition feature of SFAS No. 87 and SFAS No. 106.

An entity that determines its postretirement benefits allowance included in its cost-based, regulated-rates on the basis of SFAS No. 87 and SFAS No. 106 adopts that same delayed recognition feature for ratemaking purposes. That is, changes in the postretirement benefit obligation and assets set aside to meet those obligations are not included in rates when they occur but rather are included in rates systematically and gradually in subsequent periods. The recognition of an asset or liability to reflect the funded status of postretirement benefit plans which would otherwise be charged to accumulated other comprehensive income therefore constitutes a measurement of the

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[2] Financial Accounting Standards Board's Statements of Financial Accounting Standards No. 87, *Employer's Accounting for Pensions* and No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.*

[3] *Ibid. See Summary - Fundamentals of Pension Accounting.*

changes in postretirement obligations and the value of plan assets that are to be included in the determination of rates in subsequent periods in so far as the amounts that would otherwise be charged to accumulated other comprehensive income relate to the cost-based, rate-regulated segment of the entity.

Under the Commission's accounting requirements, regulatory assets or liabilities are to be established for amounts that would have been included in net income or accumulated other comprehensive income determinations in the current period under the general requirements of the Uniform Systems of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

Therefore, in the circumstances described above and provided that it is probable that the postretirement benefit allowance to be included in rates in future periods will continue to be calculated on the basis of SFAS No. 87 and SFAS No. 106, entities shall recognize a regulatory liability or asset for the funded status asset or liability otherwise chargeable to accumulated other comprehensive income under SFAS No. 158 related to its cost-based, rate-regulated business segments.

Further, the funded status asset or liability that must be recognized under SFAS No. 158, as well as any related regulatory liability or asset is not amortized over future periods. At each measurement date, the entry recorded for the previous measurement date is reversed and the computation redone. A new funded status asset or liability and related regulatory liability or asset would be recognized, if required, at the new measurement date.

This guidance is for accounting purposes only and does not limit the Commission from reviewing the reasonableness of the elements of postretirement benefit expense included in future rate proceedings before the Commission.

4. FERC FORM NOS. 1, 1-F, 2, 2-A, 3-Q, 6 AND 6-Q REPORTING REQUIREMENTS

Background: The Commission's annual and quarterly FERC Form Nos. 1, 1-F, 2, 2-A, 3-Q, 6 and 6-Q contain a supporting schedule for reporting accumulated other comprehensive income. The supporting schedule contains a column for reporting the minimum pension liability chargeable to accumulated other comprehensive income under the requirements of SFAS No. 87 as it existed prior to the amendments called for by SFAS No. 158. SFAS No. 158 eliminates the concept of recognition of a minimum pension liability by amending paragraph numbers 36 - 38 of SFAS No. 87.

Question: How should jurisdictional entities complete the supporting schedule for reporting accumulated comprehensive income contained in the Commission's Form Nos. 1, 1-F, 2, 2-A, 3-Q, 6, and 6-Q for amounts related to the funded status of defined pension and other postretirement benefit plans under SFAS No. 158?

Response: In the period of initial application of SFAS No. 158, a jurisdictional entity that had recorded a minimum pension liability in accumulated other comprehensive income in preceding periods, should report in column (c), Line No. 8, the amount required to produce a zero balance in column (c), Line No. 10 for the minimum pension liability adjustment. In periods subsequent to the initial application of SFAS No. 158, a jurisdictional entity should report in column (e), Line No. 7, the amount of reclassification adjustments of accumulated other comprehensive income as a result of gains or losses, prior service costs or credits and transition assets or obligations related to postretirement benefit plans being recognized as components of net periodic benefit cost of the period. All other amounts properly included in accumulated other comprehensive income, in the year of initial application and in subsequent periods related to the funded status of defined benefit postretirement benefit plans should be reported in column (e), Line No. 8.

Additionally filers should provide full particulars in a footnote to this schedule concerning amounts reported related to the funded status of defined benefit postretirement plans consistent with the disclosure requirements of SFAS No. 158.

5. ADJUSTMENTS TO RETAINED EARNINGS

Background: SFAS No. 158 requires an employer to measure the funded status of postretirement benefit plans as of the date of its year-end statement of financial position, with limited exceptions. Paragraph numbers 17 - 20 of SFAS No. 158 indicate that implementing the measurement date provisions of the Statement may require an adjustment to the opening balance of retained earnings.

Question: How should FERC jurisdictional entities recognize any required adjustment to the opening balance of retained earnings? Is a separate filing requesting Commission approval of that accounting required?

Response: Public utilities and licensees, natural gas companies, oil pipeline companies and centralized service companies should use the accounts shown below to record any adjustment to the opening balance of retained earnings required in connection with implementing SFAS No. 158 for FERC accounting and reporting purposes.

This guidance letter constitutes the required Commission approval for use of these accounts for this purpose and a separate filing with the Commission requesting such approval is not needed. Public utilities and licensees, natural gas companies and oil pipeline companies should report any amounts recorded in the accounts listed below on the lines designated for these accounts in the Statement of Retained Earnings schedule contained in the FERC Form Nos. 1, 1-F, 2, 2-A, 3-Q, 6 and 6-Q.

Jurisdictional Entity	**FERC Accounts**
Public utilities and licensees (Major and Nonmajor)	Account 439, Adjustments to retained earnings
Natural gas companies	Account 439, Adjustments to retained earnings
Oil pipeline companies	Account 705, Prior period adjustments to beginning retained income account
Centralized service companies	
□ Periods prior to January 1, 2008	Account 216, Unappropriated retained earnings
□ January 1, 2008 and subsequent periods	Account 439, Adjustments to retained earnings

6. SUBSIDIARY FINANCIAL STATEMENTS

Background: Paragraph number 1 of SFAS No. 158 indicates that the Statement applies to single-employer defined benefit postretirement plans and does not change the accounting for a multiemployer plan. Paragraph number 68 of SFAS No. 87 and paragraph number 81 of SFAS 106 state that an employer participating in a multiemployer pension or other postretirement benefit plan shall recognize as net pension or other postretirement benefit cost the required contribution for the period and shall recognize as a liability any contribution due and unpaid. Questions and answers 86 and 87 in the FASB Special Report, A Guide to Implementation of Statement 87 on Employer's Accounting for Pensions, indicate that subsidiaries of an organization that has a defined benefit pension plan that covers employees at the parent company and subsidiary level should account for its participation in the overall single-employer pension plan as a participation in a multiemployer plan provided (a) each subsidiary is required to contribute to the pension plan based on a predetermined formula (for example, on a percentage-of-salary basis), (b) plan assets are not segregated or restricted on a subsidiary-by-subsidiary basis, and (c) if a subsidiary withdraws from the pension plan, the pension obligations for its employees are retained by the pension plan as opposed to being allocated to the withdrawing subsidiary.

Question: How should a FERC jurisdictional entity account for its participation in a parent company sponsored pension or other defined benefit postretirement plan?

Answer: Public utilities and licensees, natural gas companies, oil pipeline companies and centralized service companies who prepare a separate financial statement for submission to the U.S. Securities and Exchange Commission, investors, or others and account for its participation in parent sponsored postretirement benefit plans as participation in a single-employer plan or multiple-employer plan in accordance with SFAS Nos. 87, 106, and 158, must follow the same accounting and reporting in financial statements contained in its FERC Form Nos. 1, 1-F, 2, 2-A, 3-Q, 6, 6-Q and 60.

7. COST-OF-SERVICE TARIFFS/FORMULA RATE

Background: Jurisdictional entities may have cost-of-service tariffs or formula rates under which amounts billed each month will change based on amounts recorded pursuant to the Commission's Uniform System of Accounts. Under the tariff or formula rate, only amounts recorded in certain specified accounts affect the monthly billings.

Question: May jurisdictional entities include in their monthly billings any amounts recognized or reclassified in connection with the implementation of SFAS No. 158 for FERC reporting purposes?

Response: No. Adoption of the accounting guidance contained in this letter is for FERC accounting and reporting purposes only, and may not affect the measurement or periods in which amounts are included in jurisdictional entities' billing determinations without prior regulatory approval. If an entity's billing determinations are affected by the adoption of the guidance contained in this letter, the entity shall make a filing with the proper rate regulatory authorities before implementing the accounting change for billing purposes.

The Commission delegated authority to act on this matter to the Chief Accountant under 18 C.F.R. § 375.303 (2006). This guidance letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2006).

Janice Garrison Nicholas
Chief Accountant and Director
Division of Financial Regulation

EXHIBIT ____ (LK-7)

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2019-00271
JURISDICTIONAL RATE BASE SUMMARY
AS OF NOVEMBER 30, 2019
AS OF MARCH 31, 2021

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SEE BELOW

SCHEDULE B-1

WITNESS RESPONSIBLE:
S. E. LAWLER

LINE NO.	RATE BASE COMPONENT	SUPPORTING SCHEDULE REFERENCE	BASE PERIOD	13 MONTH AVG. FORECAST PERIOD	
1	Adjusted Jurisdictional Plant in Service	B-2	$1,842,849,263	$1,949,359,830	
2	Accumulated Depreciation and Amortization	B-3 / B-3.2	(785,055,340)	(795,436,884)	(1)
3	Net Plant in Service (Line 1 + Line 2)		1,057,793,923	1,153,922,946	
4	Construction Work in Progress	B-4	0	0	(2)
5	Cash Working Capital Allowance	B-5	17,650,833	14,965,228	
6	Other Working Capital Allowances	B-5	38,513,301	38,513,301	
7	Other Items:				
8	Customers' Advances for Construction	B-6	0	0	
9	Investment Tax Credits	B-6	0	0	
10	Deferred Income Taxes	B-6	(169,836,375)	(198,366,893)	(3)
11	Excess ADIT	B-6	(68,641,581)	(63,555,450)	
12	Other Rate Base Adjustments	WPF-6a	449,251	948,688	
13	Jurisdictional Rate Base (Line 3 through Line 12)		$875,929,352	$946,427,820	

(1) Includes an average of the annualized depreciation adjustment per Schedule D-2.24.
(2) The Company is not requesting to include recovery of CWIP in base rates.
(3) Includes an adjustment to ADIT to reflect annualized depreciation as calculated on Schedule D-1 and Schedule D-2.24.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2019-00271
ALLOWANCE FOR WORKING CAPITAL
AS OF NOVEMBER 30, 2019
AS OF MARCH 31, 2021

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SEE BELOW

SCHEDULE B-5
PAGE 1 OF 1
WITNESS RESPONSIBLE:
C. M. JACOBI

LINE NO.	WORKING CAPITAL COMPONENT	DESCRIPTION OF METHODOLOGY USED TO DETERMINE JURISDICTIONAL REQUIREMENT	WORK PAPER REFERENCE NUMBER	TOTAL COMPANY BASE PERIOD	TOTAL COMPANY FORECASTED PERIOD	JURISDICTIONAL BASE PERIOD	JURISDICTIONAL FORECASTED PERIOD
					$		$
1	Cash Element of	Based on 1/8 Oper. & Maint. Expense	WPB-5.1a	20,105,709	17,511,806	17,650,833	14,965,228
2	Working Capital	less purchased gas costs or fuel and					
3		purchased power expenses.					
4							
5	Other Working Capital:						
6	Fuel Inventory						
7	Coal	(1)	WPB-5.1i	14,355,520	14,355,520	14,355,520	14,355,520
8	Oil	(1)	WPB-5.1i	5,162,494	5,162,494	5,162,494	5,162,494
9	Natural Gas	(1)	WPB-5.1i	0	0	0	0
10	Propane - Woodsdale	(1)	WPB-5.1i	0	0	0	0
11	Total Fuel Inventory			19,518,014	19,518,014	19,518,014	19,518,014
12							
13	Gas Enricher Liquids	(1)	WPB-5.1b	3,659,201	3,659,201	0	0
14							
15	Gas Stored Underground	(1)	WPB-5.1g	2,239,894	2,239,894	0	0
16							
17	Emission Allowances	(1)	WPB-5.1j	0	0	0	0
18							
19	Materials and Supplies	(1)	WPB-5.1c	19,464,929	19,464,929	18,759,249	18,759,249
20							
21	Prepayments	(1)	WPB-5.1e	1,056,698	1,398,146	236,038	236,038
22							
23	Total Other Working Capital			45,938,736	46,280,184	38,513,301	38,513,301
24							
25	Total Working Capital			66,044,445	63,791,990	56,164,134	53,478,529

N.C - Not calculated

(1) The Base Period is the ending period balance. The Forecasted Period is a 13 month average balance.

DUKE ENERGY KENTUCKY, INC.
ELECTRIC DEPARTMENT
CASE NO. 2019-00271
PREPAYMENTS
FOR THE BASE PERIOD AND THE FORECASTED PERIOD

WPB-5.1e
WITNESS RESPONSIBLE:
C. M. JACOBI

LINE NO.	DESCRIPTION	TOTAL COMPANY (1)	ALLOC. TO ELEC DEPT. %	AMOUNT	JURIS. ALLOCATION CODE	%	JURISDIC. AMOUNT
1	Base Period - Ending Balance						
2	KPSC Maintenance Tax - Gas	102,081	0.00% (2)	0	DNON	0.000	0
3	KPSC Maintenance Tax - Elec	661,288	100.00% (2)	661,288	DNON	0.000	0
4	Inter-Co Prepaid Insurance - Elec	280,124	100.00%	280,124	DALL	100.000	280,124
5	Inter-Co Prepaid Insurance - Gas	57,291	0.00%	0	DALL	100.000	0
6	Collateral Asset	(44,086)	100.00%	(44,086)	DALL	100.000	(44,086)
7	Total	1,056,698		897,326			236,038
8							
9	Forecasted Period - 13 Month Average Balance						
10	KPSC Maintenance Tax - Gas	134,102	0.00% (2)	0	DNON	0.000	0
11	KPSC Maintenance Tax - Elec	970,715	100.00% (2)	970,715	DNON	0.000	0
12	Inter-Co Prepaid Insurance - Elec	280,124	100.00%	280,124	DALL	100.000	280,124
13	Inter-Co Prepaid Insurance - Gas	57,291	0.00%	0	DALL	100.000	0
14	Collateral Asset	(44,086)	100.00%	(44,086)	DALL	100.000	(44,086)
15	Total	1,398,146		1,206,753			236,038

DUKE ENERGY KENTUCKY
CASE NO. 2019-00271
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(f)

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807 KAR 5:001, SECTION 16(6)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital use to determine its revenue requirements.

Response:

See attached.

Witness Responsible: Sarah E. Lawler

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2019-00271
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2021

FR 16(6)(f) Forecast Period
PAGE 1 OF 5
WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description	Source	Amount
1	Capitalization Allocated to Electric Operations	Page 2 of 5	1,048,999,655
2	Adjustments to Plant in Service	Sch. B-2.2 & B-3.1	(99,181,994)
3	Assets per Books not included in Rate Base:		
4	Other Property and Investments	Schedule B-8	(5,960,925)
5	CWIP	Sch. B-4	(60,274,377)
6	Cash	Schedule B-8	(3,527,306)
7	Other Current Assets	Schedule B-8	(25,997,905)
8	Other Regulatory Assets	Schedule B-8	(102,820,241)
9	Other Deferred Debits	Schedule B-8	(7,700,553)
10	Subtotal		(206,281,307)
11	Liabilities per Books not included in Rate Base:		
12	Other Current liabilities	Schedule B-8	45,724,508
13	Other Non-current liabilities	Schedule B-8	24,349,413
14	Deferred Credits	Schedule B-8	118,186,370
15	Subtotal		188,260,291
16	Items included in Rate Base:		
17	Cash Working Capital Formula	Sch.B-5	14,965,227
18	Depreciation adjustment not included in capitalization	Sch. D-2.24	2,294,047
19	Capitalization / Rate Base Differences		(2,628,099)
20	Subtotal		14,631,175
21	Total Variance		(102,571,835)
22	Electric Rate Base	Schedule B-1	946,427,820

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2019-00271
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2021

FR 16(6)(f) Forecast Period
PAGE 2 OF 5
WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description		Capitalization Total	Capitalization Electric
1	Total Forecasted Period Capitalization	(1)	1,449,897,246	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	5,796,825	
4	Electric Non-jurisdictional Rate Base	(2)	(2,047,050)	
5	Non-jurisdictional Rate Base	(2)	(24,043,249)	
6				
7	Jurisdictional Capitalization		1,470,190,720	
8				
9	Electric Jurisdictional Rate Base Allocation %	(2)	71.146%	1,045,981,890
10				
11	Plus: Jurisdictional Electric ITC	(3)		3,017,765
12				
13	Total Allocated Capitalization			1,048,999,655

Notes:
(1) Schedule J-1, page 1.
(2) Page 3 of 5.
(3) Schedule B-6, page 1.

DUKE ENERGY KENTUCKY, INC.
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THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2021

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WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description	Schedule Reference	Total Company	Gas Excl. of Facilities Devoted to Other Than DE-Kentucky Custs.	Gas Non-Juris.	Electric Jurisdictional	Electric Non-Juris.	Non-Jurisdictional
1	Total Utility Plant in Service (Accts 101 & 106) (B)	Sch B-2, (D)	2,619,964,546	658,273,526	12,331,190	1,949,359,830	0	0
2								
3	Additions:							
4	Construction Work in Progress (Account 107)	Sch B-4, (D)	86,786,984	26,512,607		60,274,377	0	0
5								
6	Fuel Inventory	Sch B-5	19,518,014	0	0	19,518,014	0	0
7								
8	Materials & Supplies -							
9	Propane Inventory (Account 151) (B)	WPB-5.1b	3,659,201	1,309,994	2,349,207	0	0	0
10	Other Material and Supplies (Accts. 154 & 163) (B)	WPB-5.1c	19,464,929	705,680	0	18,759,249	0	0
11	Total Materials & Supplies		23,124,130	2,015,674	2,349,207	18,759,249	0	0
12								
13	Gas Stored Underground (Account 164) (B)	WPB-5.1f	2,239,894	2,239,894	0	0	0	0
14								
15	Prepayments (Account 165) (B)	WPB-5.1e	1,398,146	57,291	134,102	236,038	970,715	0
16								
17	Emission Allowances (Account 158)	WPB-5.1i	0	0	0	0	0	0
18								
19	Cash Working Capital Allowance	WPB-5.1a	17,511,805	2,546,578	0	14,965,227	0	0
20								
21	Other Rate Base Items	WPF-6a	1,128,554	179,866	0	948,688	0	0
22	Total Additions		151,707,527	33,551,910	2,483,309	114,701,593	970,715	0
23								
24	Deductions:							
25	Reserve for Accumulated Depreciation (Acct 108) (B)	Sch B-3.2, (D)	984,715,341	183,825,230	7,747,274	793,142,837 (A)	0	0
26								
27	Accum. Deferred Income Taxes (Accts 190, 282, & 283) (B)	Sch B-6, WPB-6a	289,556,862	65,428,387	574,746 (C)	199,510,480	0	24,043,249
28								
29	Customer Advances for Construction (Account 252)	WPB-6a	1,593,310	1,593,310	0	0	0	0
30								
31	Total Regulatory Liability - Excess Deferred Taxes	Sch B-6	96,106,293	32,238,133	312,710 (C)	63,555,450	0	0
32								
33	Investment Tax Credits	Sch B-6	3,400,709	0	382,944	0	3,017,765	0
34	Total Deductions		1,375,372,515	283,085,060	9,017,674	1,056,208,767	3,017,765	24,043,249
35								
36	Net Original Cost Rate Base		1,396,299,558	408,740,376	5,796,825	1,007,852,656	(2,047,050)	(24,043,249)
37								
38	Jurisdictional Rate Base Ratio		100.000%	29.273%	0.415%	72.180%	-0.147%	-1.722%
39								
40	Jurisdictional Rate Base Ratio - Excluding Non-Jurisdictional		100.000%	28.854%		71.146%		

Notes:
(A) Does not include depreciation annualization adjustment per Commission precedent.
(B) Adjusted for non-jurisdictional gas plant.
(C) FR 16(6)(f), page 4.
(D) Company records.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2019-00271
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2021

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WITNESS RESPONSIBLE:
S. E. LAWLER

LINE NO.	Description	WPB-6b	Allocation % (A)	To Be Eliminated (Col. 1 * Col. 2)
		(1)	(2)	(3)
1	Investment Tax Credit - 3%	0	0.97%	0
2	Liberalized Depreciation	(59,252,186)	0.97%	(574,746)
3	Excess Deferred Taxes	(32,238,133)	0.97%	(312,710)

(A) Ratio of Gas Plant Devoted to Other Than Duke Energy Kentucky Customers to Total Plant.

DUKE ENERGY KENTUCKY, INC.
ELECTRIC DEPARTMENT
CASE NO. 2019-00271
COMPUTATION OF RATIO OF PLANT DEVOTED TO OTHER THAN
DE-KENTUCKY CUSTOMERS TO TOTAL PLANT FOR ELIMINATION PURPOSES
AS OF MARCH 31, 2021

FR 16(6)(f) Forecast Period
PAGE 5 OF 5
WITNESS RESPONSIBLE:
S. E. LAWLER

LINE NO.	Description			Amount (1)
1	Total Net Gas Plant before Adjustment			
2	of Facilities Devoted to Other	Original Cost	$	658,273,526
3	Than DE-Kentucky Customers	Accum Depr.		183,825,230
4		Net Plant	$	474,448,296
5				
6	Total Net Gas Plant Devoted to	Original Cost	$	12,331,190
7	Other Than DE-Kentucky Customers	Accum Depr.		7,747,274
8		Net Plant	$	4,583,916
9				
10				
11	Ratio of Plant Devoted to Other Than			
12	DE-Kentucky Customers to Total Plant (Line 8 / Line 4)			0.97%

(1) Company Records.

CONFIDENTIAL

EXHIBIT ____ (LK-8)

OUCC
IURC Cause No. 45253
Data Request Set No. 17
Received: September 5, 2019

OUCC 17.33

Request:

Please state where the $150,740,000 "prepaid pension asset" claimed by Petitioner as of December 31, 2020 can be found on Petitioner's balance sheet. If it is not located in the asset section of the balance sheet, please explain why not.

Response:

See the table below for the Balance Sheet lines where the amounts included in the Prepaid Pension Asset balance can be found and the amount included in each of these lines that is a component of the Prepaid Pension balance.

A portion of the net Prepaid Pension balance is located in the "Other Noncurrent Liabilities" section of the Balance Sheet. The portion in the Other Noncurrent Liabilities section of the Balance Sheet represents the funded status of two pension plans included in the overall net asset. The funded status for these plans is a non-current liability because the amount of each plan's projected benefit obligation exceeds the amount of each plan's associated plan assets.

Balance Sheet Lines (1):	**Amount**
Other Noncurrent Assets:	
Regulatory Assets	$ 181,661,621
Other	39,273,767
Other Noncurrent Liabilities:	
Accrued Pension and Other Post-Retirement Benefit Costs	(69,853,149)
Other	(342,122)
Total	$ 150,740,117
(1) See: Petitioner's Exhibit 3-A pages 4-5	

Witness: Christopher M. Jacobi / Diana L. Douglas

OUCC
IURC Cause No. 45253
Data Request Set No. 17
Received: September 5, 2019

OUCC 17.34

Request:

Please provide the historic calculation of Petitioner's claimed "prepaid pension asset" from inception to the present, including the amount of pension contributions and pension cost recorded for each calendar year included in this calculation.

Objection:

Duke Energy Indiana objects to this request as overly broad and unduly burdensome because it is not limited to a reasonable or relevant time period. Duke Energy Indiana has provided the information for the years it has available.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: Please see Confidential Attachment OUCC 17.34-A for development of the prepaid pension asset for periods 2010 through 2020.

Witness: Diana L. Douglas

Duke Energy Indiana
OUCC 17.34
Prepaid Pension Asset
December 31, 2020

Year [(A)]		Cash Contributions		Net Periodic Benefit Cost		Other		Ending Balance
2009	$	-	$	-	$	-	$	129,081,709
2010		45,520,526		(14,478,741)		74,803		160,198,297
2011		52,265,014		(13,946,120)		(75,152)		198,442,039
2012		-		(9,463,299)		-		188,978,740
2013		-		(18,956,111)		(157,198)		169,865,431
2014		-		(10,662,819)		-		159,202,612
2015		19,226,473		(10,482,418)		-		167,946,667
2016		9,271,841		(6,400,136)		-		170,818,371
2017		63,279		(4,173,625)		-		166,708,025
2018		8,462,789		453,820		-		175,624,634
2019	$	-	$	(11,078,505)	$	-	$	164,546,130
2020	$	-	$	(10,184,743)	$	-	$	154,361,386
Ending balance: qualified pension							$	154,361,386
Add: nonqualified pension balances (2018)								(3,621,206)
Prepaid pension asset - December 31, 2020							**$**	**150,740,180**

(A) - Information for the years 2000 through 2009 was not provided because the amounts are not readily available.

EXHIBIT ____ (LK-9)

OUCC
IURC Cause No. 45253
Data Request Set No. 33
Received: September 27, 2019

OUCC 33.9

Request:

Please state the percentage of pension cost capitalized during the period 2000 – 2018.

Objection:

Duke Energy Indiana objects to this request to the extent it requires a calculation or compilation not maintained in the normal course of business and that it has not performed and which it objects to performing.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

The following table provides capitalization percentages for the period 2010 - 2018:

Year	Capitalization Percentage [A]
2018	34.8%
2017	31.6%
2016	27.0%
2015	27.5%
2014	24.8%
2013	27.5%
2012	29.8%
2011	20.7%
2010	21.1%

A - Information prior to 2010 is not readily available.

Witness: Renee H. Metzler

EXHIBIT ____ (LK-10)

IG
IURC Cause No. 45253
Data Request Set No. 18
Received: September 6, 2019

IG 18.1

Request:

Please provide the operating and maintenance expenses incurred in 2016 for the Wabash Units 2-6. Please provide the same information for calendar year 2015. Please provide a description of the costs incurred and the FERC account where those expenses are recorded.

Objection:

Duke Energy Indiana objects to this data request on the basis that it is vague and ambiguous, particularly the use of the term "a description of the costs incurred." Duke Energy Indiana also objects to this request on the grounds that it seeks information that is publicly available and is as easily accessible by the IG as Duke Energy Indiana.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

The table below summarizes the 2015 and 2016 operating and maintenance expenses for Wabash River Steam Units 2-6 from public FERC Form 1 "page 402" data. Please note that Wabash River Units 2-6 ceased operation on April 16, 2016.

FERC Form 1 "Page 402" Data Compilation **Wabash River Steam Units 2-6**

Line	Group	FERC Account	Description	2015	2016
19	Operation	500	Operation Supervision and Engineering	$2,172,006	$727,541
20	Operation	501	Fuel	$58,271,729	$12,027,615
22	Operation	502	Steam Expenses	$617,630	$202,039
23	Operation	503	Steam from Other Sources	$0	$0
24	Operation	504	Less Steam Transferred-Cr.	$0	$0
25	Operation	505	Electric Expenses	-$324,904	-$282,027
26	Operation	506	Miscellaneous Steam Power Expenses	$4,715,324	$1,971,665
27	Operation	507	Rents	$0	$0
28	Operation	509	Allowances	$0	$0
29	Maintenance	510	Maintenance Supervision and Engineering	$1,001,842	$263,451
30	Maintenance	511	Maintenance of Structures	$4,174,293	$2,483,897
31	Maintenance	512	Maintenance of Boiler Plant	$3,177,472	$454,859
32	Maintenance	513	Maintenance of Electric Plant	$785,890	$81,245
33	Maintenance	514	Maintenance of Miscellaneous Steam Plant	$1,004,014	-$145,302
			Total	$75,595,296	$17,784,983

Witness: James Michael Mosley

EXHIBIT ____ (LK-11)

OUCC
IURC Cause No. 45253
Data Request Set No. 29
Received: September 23, 2019

OUCC 29.11

Request:

Provide the non-fuel O&M expense by FERC O&M expense account and each other operating expense, including, but not limited to, A&G expense, other taxes expense, and depreciation expense related to Gallagher Units 1 and 3 for each of the last three years these units operated prior to their retirements. In addition, provide the month in which each unit was retired.

Objection:

Duke Energy Indiana objects to this request to the extent it requires a calculation or compilation not maintained in the normal course of business and that it has not performed and which it objects to performing.

Response:

Subject to and without waiving or limiting its objections and in the spirit of cooperation, Duke Energy Indiana responds as follows:

The estimated amount of depreciation expense for Gallagher Units 1 & 3 for 2009 to 2011 is as follows:

2009	$5,645,918
2010	$5,664,536
2011	$5,678,940

The non-fuel O&M expenses for Gallagher Unit 1 and Unit 3 for 2009 to 2011 are as follows:

Duke Energy Indiana, LLC Attachment OUCC 29.11

Gallagher O&M for Unit 1 and Unit 3 [1]

	Gallagher Unit 1			Gallagher Unit 3		
FERC Account	2009	2010	2011	2009	2010	2011
500	326	375	345	326	375	344
502	44	64	221	40	62	221
505	3	9	1	3	9	1
506	442	346	525	443	334	518
507		6	2		6	2
510	399	472	455	400	464	454
511	366	439	413	357	440	372
512	1,969	1,998	1,757	1,550	1,789	1,656
513	280	473	1,624	283	237	165
514	386	584	253	391	586	228
546	1	1		1	1	
549	1			1		
553	165	181	183	165	181	183
570	97	41	7	82	45	17
588		1			1	
920	65	50	55	43	50	55
921	(1)	6	9	(1)	6	9
923	14	15	32	15	15	32
926	640	724	959	634	673	521
930.1		1			1	
930.2	5	3	2	5	3	2
	5,203	**5,788**	**6,843**	**4,738**	**5,279**	**4,780**

1 FERC Account 501 Fuel excluded

Gallagher Units 1 and 3 retired on January 31, 2012, per OASIS (https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements(Public)_2019-02-28.pdf).

Witness: Keith Pike

EXHIBIT ____ (LK-12)

OUCC
IURC Cause No. 45253
Data Request Set No. 29
Received: September 23, 2019

OUCC 29.3

Request:

Refer to the Direct Testimony of Christa Graft at p. 10:7-15 wherein she addresses the Company's request to defer Customer Connect O&M expenses.

a. Provide the 2018 and 2019 O&M expenses, related payroll tax expenses, and carrying costs that will be deferred if the retroactive component of the Company's request is authorized. Provide all data, assumptions, and calculations, including electronic spreadsheets in live format with all formulas intact. In the calculations, indicate if the Company proposes to subtract ADIT from the rate base amount used to calculate carrying costs. In the calculations, indicate if the Company proposes to subtract ADIT from the rate base amount used to calculate carrying costs. If not, then explain why not.

b. Provide the 2020 carrying costs that will be deferred if the prospective component of the Company's request is authorized. Provide all data, assumptions, and calculations, including electronic spreadsheets in live format with all formulas intact. In the calculations, indicate if the Company proposes to subtract ADIT from the rate base amount used to calculate carrying costs. If not, then explain why not.

c. Provide the Company's projections for the years 2021 through 2025 of the O&M expenses, related payroll tax expenses, depreciation expense, and carrying costs that will be deferred if the prospective component of the Company's request is authorized and the deferred costs are not included and recovered in the base revenue requirement in those years. Provide all data, assumptions, and calculations, including electronic spreadsheets in live format with all formulas intact. In the calculations, indicate if the Company proposes to subtract ADIT from the rate base amount used to calculate carrying costs. If not, then explain why not.

d. Provide the projected in-service date of the Customer Connect project.

e. Provide the service life and proposed amortization/depreciation rate for the Customer Connect project. Provide a copy of all source documents relied on for this information as well as electronic spreadsheets in live format with all formulas intact.

Objection:

Duke Energy Indiana objects to this request to the extent it requires a calculation or compilation not maintained in the normal course of business and that it has not performed and which it objects to performing. Duke Energy Indiana objects to the question on the grounds that it mischaracterizes the request of Duke Energy Indiana relative to Customer Connect as "retroactive."

Response:

Subject to and without waiving or limiting its objections and in the spirit of cooperation, Duke Energy Indiana responds as follows:

a. Please see Attachment OUCC 29.3-A for an estimate of deferred O&M (including related payroll taxes) and associated carrying costs. Answering further, Duke Energy Indiana does not propose to subtract ADIT from the rate base amount used to calculate carrying costs because the Company includes accumulated deferred income tax balances as a zero-cost resource in its cost of capital calculations in accordance with Indiana regulatory practice, not as deductions from rate base.

b. See the response to part a above.

c. Please see Attachment OUCC 29.3-A for an estimate of deferred O&M (including related payroll taxes) and associated carrying costs. For an estimate of deferred amortization, please see Attachment OUCC 29.3-B. For an estimate of deferred post-in-service carrying costs, please see Attachment OUCC 29.3-C. Answering further, Duke Energy Indiana does not propose to subtract ADIT from the rate base amount used to calculate carrying costs because the Company includes accumulated deferred income tax balances as a zero-cost resource in its cost of capital calculations in accordance with Indiana regulatory practice, not as deductions from rate base.

d. The Customer Connect project has multiple in-service dates, as the components of the project are being placed in service as completed. All components of the Customer Connect project are projected to be in service by October 1, 2022.

e. The Company's amortization guidelines for software projects are provided in the below paragraph from the Duke Energy Regulated Electric & Gas Capitalization Guidelines. The Customer Connect program team worked with Asset Accounting early in the program and jointly determined the core meter-to-cash solution being implemented in late 2022 will be amortized over 15 years, and the early deliverables including Analytics, Customer Engagement and Universal Bill will be amortized over 5 years.

Amortization Period

- When determining the amortization period, entities should consider the effects of obsolescence, technology, competition, and other economic factors. Consideration should be given to rapid changes that may be occurring in the development of software products, software operating systems, or computer hardware and whether management intends to replace any technologically inferior software or hardware. Given the history of rapid changes in technology, software often has had a relatively short useful life.
- Amortization of functionally independent modules should begin when the software / module is ready for its intended use, regardless of whether the software / module will be placed in service in planned stages that may extend beyond a reporting period.
- Computer software is ready for its intended use after all "substantial testing" is completed.

Witness: Christa L. Graft (a, b, c) / Retha I. Hunsicker (d, e) / Diana L. Douglas (e)

Duke Energy Indiana, LLC
Customer Connect Deferral Estimates
O&M with Carrying Costs

Attachment OUCC 29.3-A

		Carrying Cost Basis Calculation				Carrying Cost Rate 1/			Current Period Carrying Cost			Cumulative Carrying Cost		
	O&M Deferred ($)	Prior Period Cumulative	1/2 Current Period	Prior Period Carrying Cost	Total Carrying Cost Basis	Debt Rate	Equity Rate	Total Rate	Debt	Equity	Total	Debt	Equity	Total
Jan-18	$ 292,924.19	$ -	$ 146,462.10	$ -	$ 146,462.10	1.78%	4.42%	6.20%	$ 217.25	$ 539.47	$ 756.72	$ 217.25	$ 539.47	$ 756.72
Feb-18	45,650.82	292,924.19	22,825.41	756.72	316,506.32	1.78%	4.42%	6.20%	469.48	1,165.80	1,635.28	686.73	1,705.27	2,392.00
Mar-18	111,020.54	338,575.01	55,510.27	2,392.00	396,477.28	1.78%	4.42%	6.20%	588.11	1,460.36	2,048.47	1,274.84	3,165.63	4,440.47
Apr-18	419,528.13	449,595.55	209,764.07	4,440.47	663,800.09	1.78%	4.42%	6.20%	984.64	2,445.00	3,429.64	2,259.48	5,610.63	7,870.11
May-18	83,299.50	869,123.68	41,649.75	7,870.11	918,643.54	1.78%	4.42%	6.20%	1,362.65	3,383.67	4,746.32	3,622.13	8,994.30	12,616.43
Jun-18	148,542.81	952,423.18	74,271.41	12,616.43	1,039,311.02	1.78%	4.42%	6.20%	1,541.64	3,828.13	5,369.77	5,163.77	12,822.43	17,986.20
Jul-18	148,390.26	1,100,965.99	74,195.13	17,986.20	1,193,147.32	1.78%	4.42%	6.20%	1,769.84	4,394.76	6,164.60	6,933.61	17,217.19	24,150.80
Aug-18	139,645.59	1,249,356.25	69,822.80	24,150.80	1,343,329.85	1.78%	4.42%	6.20%	1,992.61	4,947.93	6,940.54	8,926.22	22,165.12	31,091.34
Sep-18	385,423.10	1,389,001.84	192,711.55	31,091.34	1,612,804.73	1.78%	4.42%	6.20%	2,392.33	5,940.50	8,332.83	11,318.55	28,105.62	39,424.17
Oct-18	37,021.32	1,774,424.94	18,510.66	39,424.17	1,832,359.77	1.78%	4.42%	6.20%	2,718.00	6,749.19	9,467.19	14,036.55	34,854.81	48,891.36
Nov-18	77,411.91	1,811,446.26	38,705.96	48,891.36	1,899,043.58	1.78%	4.42%	6.20%	2,816.91	6,994.81	9,811.72	16,853.46	41,849.62	58,703.08
Dec-18	249,402.97	1,888,858.17	124,701.49	58,703.08	2,072,262.74	1.78%	4.42%	6.20%	3,073.86	7,632.83	10,706.69	19,927.32	49,482.45	69,409.77
Jan-19	1,107,261.83	2,138,261.14	553,630.92	69,409.77	2,761,301.83	1.79%	4.29%	6.08%	4,118.94	9,871.65	13,990.59	24,046.26	59,354.10	83,400.36
Feb-19	315,252.88	3,245,522.97	157,626.44	83,400.36	3,486,549.77	1.79%	4.29%	6.08%	5,200.77	12,464.42	17,665.19	29,247.03	71,818.52	101,065.55
Mar-19	301,215.51	3,560,775.85	150,607.76	101,065.55	3,812,449.16	1.79%	4.29%	6.08%	5,686.90	13,629.51	19,316.41	34,933.93	85,448.03	120,381.96
Apr-19	473,789.46	3,861,991.36	236,894.73	120,381.96	4,219,268.05	1.79%	4.29%	6.08%	6,293.74	15,083.88	21,377.62	41,227.67	100,531.91	141,759.58
May-19	336,083.60	4,335,780.82	168,041.80	141,759.58	4,645,582.20	1.79%	4.29%	6.08%	6,929.66	16,607.96	23,537.62	48,157.33	117,139.87	165,297.20
Jun-19	422,206.48	4,671,864.42	211,103.24	165,297.20	5,048,264.86	1.79%	4.29%	6.08%	7,530.33	18,047.55	25,577.88	55,687.66	135,187.42	190,875.08
Jul-19	580,836.33	5,094,070.90	290,418.17	190,875.08	5,575,364.15	1.79%	4.29%	6.08%	8,316.58	19,931.93	28,248.51	64,004.24	155,119.35	219,123.59
Aug-19	351,836.65	5,674,907.23	175,918.33	219,123.59	6,069,949.15	1.79%	4.29%	6.08%	9,054.34	21,700.07	30,754.41	73,058.58	176,819.42	249,878.00
Sep-19	539,372.90	6,026,743.88	269,686.45	249,878.00	6,546,308.33	1.79%	4.29%	6.08%	9,764.91	23,403.05	33,167.96	82,823.49	200,222.47	283,045.96
Oct-19	581,496.17	6,566,116.78	290,748.09	283,045.96	7,139,910.83	1.79%	4.29%	6.08%	10,650.37	25,525.18	36,175.55	93,473.86	225,747.65	319,221.51
Nov-19	366,997.66	7,147,612.95	183,498.83	319,221.51	7,650,333.29	1.79%	4.29%	6.08%	11,411.75	27,349.94	38,761.69	104,885.61	253,097.59	357,983.20
Dec-19	369,260.62	7,514,610.61	184,630.31	357,983.20	8,057,224.12	1.79%	4.29%	6.08%	12,018.69	28,804.58	40,823.27	116,904.30	281,902.17	398,806.47
Jan-20	954,635.08	7,883,871.23	477,317.54	398,806.47	8,759,995.24	1.80%	4.35%	6.15%	13,139.99	31,754.98	44,894.97	130,044.29	313,657.15	443,701.44
Feb-20	391,269.84	8,838,506.31	195,634.92	443,701.44	9,477,842.67	1.80%	4.35%	6.15%	14,216.76	34,357.18	48,573.94	144,261.05	348,014.33	492,275.38
Mar-20	459,509.79	9,229,776.15	229,754.90	492,275.38	9,951,806.43	1.80%	4.35%	6.15%	14,927.71	36,075.30	51,003.01	159,188.76	384,089.63	543,278.39
Apr-20	447,234.12	9,689,285.94	223,617.06	543,278.39	10,456,181.39	1.80%	4.35%	6.15%	15,684.27	37,903.66	53,587.93	174,873.03	421,993.29	596,866.32
May-20	493,068.15	10,136,520.06	246,534.08	596,866.32	10,979,920.46	1.80%	4.35%	6.15%	16,469.88	39,802.21	56,272.09	191,342.91	461,795.50	653,138.41
Jun-20	625,758.16	10,629,588.21	312,879.08	653,138.41	11,595,605.70	1.80%	4.35%	6.15%	17,393.41	42,034.07	59,427.48	208,736.32	503,829.57	712,565.89
Jul-20	430,503.24	11,255,346.37	215,251.62	712,565.89	12,183,163.88	1.80%	4.35%	6.15%	18,274.75	44,163.97	62,438.72	227,011.07	547,993.54	775,004.61
Aug-20	266,952.43	11,685,849.61	133,476.22	775,004.61	12,594,330.44	1.80%	4.35%	6.15%	18,891.50	45,654.45	64,545.95	245,902.57	593,647.99	839,550.56
Sep-20	489,232.75	11,952,802.04	244,616.38	839,550.56	13,036,968.98	1.80%	4.35%	6.15%	19,555.45	47,259.01	66,814.46	265,458.02	640,907.00	906,365.02
Oct-20	488,138.58	12,442,034.79	244,069.29	906,365.02	13,592,469.10	1.80%	4.35%	6.15%	20,388.70	49,272.70	69,661.40	285,846.72	690,179.70	976,026.42
Nov-20	646,762.70	12,930,173.37	323,381.35	976,026.42	14,229,581.14	1.80%	4.35%	6.15%	21,344.37	51,582.23	72,926.60	307,191.09	741,761.93	1,048,953.02
Dec-20	449,772.91	13,576,936.07	224,886.46	1,048,953.02	14,850,775.55	1.80%	4.35%	6.15%	22,276.16	53,834.06	76,110.22	329,467.25	795,595.99	1,125,063.24
Jan-21	896,333.33	14,026,708.98	448,166.67	1,125,063.24	15,599,938.89	1.80%	4.35%	6.15%	23,399.91	56,549.78	79,949.69	352,867.16	852,145.77	1,205,012.93
Feb-21	896,333.33	14,923,042.31	448,166.67	1,205,012.93	16,576,221.91	1.80%	4.35%	6.15%	24,864.33	60,088.80	84,953.13	377,731.49	912,234.57	1,289,966.06
Mar-21	896,333.34	15,819,375.64	448,166.67	1,289,966.06	17,557,508.37	1.80%	4.35%	6.15%	26,336.26	63,645.97	89,982.23	404,067.75	975,880.54	1,379,948.29
Apr-21	896,333.33	16,715,708.98	448,166.67	1,379,948.29	18,543,823.94	1.80%	4.35%	6.15%	27,815.74	67,221.36	95,037.10	431,883.49	1,043,101.90	1,474,985.39
May-21	896,333.33	17,612,042.31	448,166.67	1,474,985.39	19,535,194.37	1.80%	4.35%	6.15%	29,302.79	70,815.08	100,117.87	461,186.28	1,113,916.98	1,575,103.26
Jun-21	896,333.34	18,508,375.64	448,166.67	1,575,103.26	20,531,645.57	1.80%	4.35%	6.15%	30,797.47	74,427.22	105,224.69	491,983.75	1,188,344.20	1,680,327.95
Jul-21	896,333.33	19,404,708.98	448,166.67	1,680,327.95	21,533,203.60	1.80%	4.35%	6.15%	32,299.81	78,057.86	110,357.67	524,283.56	1,266,402.06	1,790,685.62
Aug-21	896,333.33	20,301,042.31	448,166.67	1,790,685.62	22,539,894.60	1.80%	4.35%	6.15%	33,809.84	81,707.12	115,516.96	558,093.40	1,348,109.18	1,906,202.58
Sep-21	896,333.34	21,197,375.64	448,166.67	1,906,202.58	23,551,744.89	1.80%	4.35%	6.15%	35,327.62	85,375.08	120,702.70	593,421.02	1,433,484.26	2,026,905.28
Oct-21	896,333.33	22,093,708.98	448,166.67	2,026,905.28	24,568,780.93	1.80%	4.35%	6.15%	36,853.17	89,061.83	125,915.00	630,274.19	1,522,546.09	2,152,820.28
Nov-21	896,333.33	22,990,042.31	448,166.67	2,152,820.28	25,591,029.26	1.80%	4.35%	6.15%	38,386.54	92,767.48	131,154.02	668,660.73	1,615,313.57	2,283,974.30
Dec-21	896,333.34	23,886,375.64	448,166.67	2,283,974.30	26,618,516.61	1.80%	4.35%	6.15%	39,927.77	96,492.12	136,419.89	708,588.50	1,711,805.69	2,420,394.19
Jan-22	1,109,583.33	24,782,708.98	554,791.67	2,420,394.19	27,757,894.84	1.80%	4.35%	6.15%	41,636.84	100,622.37	142,259.21	750,225.34	1,812,428.06	2,562,653.40
Feb-22	1,109,583.33	25,892,292.31	554,791.67	2,562,653.40	29,009,737.38	1.80%	4.35%	6.15%	43,514.61	105,160.30	148,674.91	793,739.95	1,917,588.36	2,711,328.31
Mar-22	1,109,583.34	27,001,875.64	554,791.67	2,711,328.31	30,267,995.62	1.80%	4.35%	6.15%	45,401.99	109,721.48	155,123.47	839,141.94	2,027,309.84	2,866,451.78
Apr-22	1,109,583.33	28,111,458.98	554,791.67	2,866,451.78	31,532,702.43	1.80%	4.35%	6.15%	47,299.05	114,306.05	161,605.10	886,440.99	2,141,615.89	3,028,056.88

Duke Energy Indiana, LLC
Customer Connect Deferral Estimates
O&M with Carrying Costs

Attachment OUCC 29.3-A

		Carrying Cost Basis Calculation				Carrying Cost Rate 1/			Current Period Carrying Cost			Cumulative Carrying Cost		
	O&M Deferred ($)	Prior Period Cumulative	1/2 Current Period	Prior Period Carrying Cost	Total Carrying Cost Basis	Debt Rate	Equity Rate	Total Rate	Debt	Equity	Total	Debt	Equity	Total
May-22	1,109,583.33	29,221,042.31	554,791.67	3,028,056.88	32,803,890.86	1.80%	4.35%	6.15%	49,205.84	118,914.10	168,119.94	935,646.83	2,260,529.99	3,196,176.82
Jun-22	1,109,583.34	30,330,625.64	554,791.67	3,196,176.82	34,081,594.13	1.80%	4.35%	6.15%	51,122.39	123,545.78	174,668.17	986,769.22	2,384,075.77	3,370,844.99
Jul-22	1,109,583.33	31,440,208.98	554,791.67	3,370,844.99	35,365,845.64	1.80%	4.35%	6.15%	53,048.77	128,201.19	181,249.96	1,039,817.99	2,512,276.96	3,552,094.95
Aug-22	1,109,583.33	32,549,792.31	554,791.67	3,552,094.95	36,656,678.93	1.80%	4.35%	6.15%	54,985.02	132,880.46	187,865.48	1,094,803.01	2,645,157.42	3,739,960.43
Sep-22	1,109,583.34	33,659,375.64	554,791.67	3,739,960.43	37,954,127.74	1.80%	4.35%	6.15%	56,931.19	137,583.71	194,514.90	1,151,734.20	2,782,741.13	3,934,475.33
Oct-22	1,109,583.33	34,768,958.98	554,791.67	3,934,475.33	39,258,225.98	1.80%	4.35%	6.15%	58,887.34	142,311.07	201,198.41	1,210,621.54	2,925,052.20	4,135,673.74
Nov-22	1,109,583.33	35,878,542.31	554,791.67	4,135,673.74	40,569,007.72	1.80%	4.35%	6.15%	60,853.51	147,062.65	207,916.16	1,271,475.05	3,072,114.85	4,343,589.90
Dec-22	1,109,583.34	36,988,125.64	554,791.67	4,343,589.90	41,886,507.21	1.80%	4.35%	6.15%	62,829.76	151,838.59	214,668.35	1,334,304.81	3,223,953.44	4,558,258.25
Jan-23	329,666.66	38,097,708.98	164,833.33	4,558,258.25	42,820,800.56	1.80%	4.35%	6.15%	64,231.20	155,225.40	219,456.60	1,398,536.01	3,379,178.84	4,777,714.85
Feb-23	329,666.67	38,427,375.64	164,833.34	4,777,714.85	43,369,923.83	1.80%	4.35%	6.15%	65,054.89	157,215.97	222,270.86	1,463,590.90	3,536,394.81	4,999,985.71
Mar-23	329,666.67	38,757,042.31	164,833.34	4,999,985.71	43,921,861.36	1.80%	4.35%	6.15%	65,882.79	159,216.75	225,099.54	1,529,473.69	3,695,611.56	5,225,085.25
Apr-23	329,666.66	39,086,708.98	164,833.33	5,225,085.25	44,476,627.56	1.80%	4.35%	6.15%	66,714.94	161,227.77	227,942.71	1,596,188.63	3,856,839.33	5,453,027.96
May-23	329,666.67	39,416,375.64	164,833.34	5,453,027.96	45,034,236.94	1.80%	4.35%	6.15%	67,551.36	163,249.11	230,800.47	1,663,739.99	4,020,088.44	5,683,828.43
Jun-23	329,666.67	39,746,042.31	164,833.34	5,683,828.43	45,594,704.08	1.80%	4.35%	6.15%	68,392.06	165,280.80	233,672.86	1,732,132.05	4,185,369.24	5,917,501.29
Jul-23	329,666.66	40,075,708.98	164,833.33	5,917,501.29	46,158,043.60	1.80%	4.35%	6.15%	69,237.07	167,322.91	236,559.98	1,801,369.12	4,352,692.15	6,154,061.27
Aug-23	329,666.67	40,405,375.64	164,833.34	6,154,061.27	46,724,270.25	1.80%	4.35%	6.15%	70,086.41	169,375.48	239,461.89	1,871,455.53	4,522,067.63	6,393,523.16
Sep-23	329,666.67	40,735,042.31	164,833.34	6,393,523.16	47,293,398.81	1.80%	4.35%	6.15%	70,940.10	171,438.57	242,378.67	1,942,395.63	4,693,506.20	6,635,901.83
Oct-23	329,666.66	41,064,708.98	164,833.33	6,635,901.83	47,865,444.14	1.80%	4.35%	6.15%	71,798.17	173,512.24	245,310.41	2,014,193.80	4,867,018.44	6,881,212.24
Nov-23	329,666.67	41,394,375.64	164,833.34	6,881,212.24	48,440,421.22	1.80%	4.35%	6.15%	72,660.63	175,596.53	248,257.16	2,086,854.43	5,042,614.97	7,129,469.40
Dec-23	329,666.67	41,724,042.31	164,833.34	7,129,469.40	49,018,345.05	1.80%	4.35%	6.15%	73,527.52	177,691.50	251,219.02	2,160,381.95	5,220,306.47	7,380,688.42
Jan-24	-	42,053,708.98	-	7,380,688.42	49,434,397.40	1.80%	4.35%	6.15%	74,151.60	179,199.69	253,351.29	2,234,533.55	5,399,506.16	7,634,039.71
Feb-24	-	42,053,708.98	-	7,634,039.71	49,687,748.69	1.80%	4.35%	6.15%	74,531.62	180,118.09	254,649.71	2,309,065.17	5,579,624.25	7,888,689.42
Mar-24	-	42,053,708.98	-	7,888,689.42	49,942,398.40	1.80%	4.35%	6.15%	74,913.60	181,041.19	255,954.79	2,383,978.77	5,760,665.44	8,144,644.21
Apr-24	-	42,053,708.98	-	8,144,644.21	50,198,353.19	1.80%	4.35%	6.15%	75,297.53	181,969.03	257,266.56	2,459,276.30	5,942,634.47	8,401,910.77
May-24	-	42,053,708.98	-	8,401,910.77	50,455,619.75	1.80%	4.35%	6.15%	75,683.43	182,901.62	258,585.05	2,534,959.73	6,125,536.09	8,660,495.82
Jun-24	-	42,053,708.98	-	8,660,495.82	50,714,204.80	1.80%	4.35%	6.15%	76,071.31	183,838.99	259,910.30	2,611,031.04	6,309,375.08	8,920,406.12
Jul-24	-	42,053,708.98	-	8,920,406.12	50,974,115.10	1.80%	4.35%	6.15%	76,461.17	184,781.17	261,242.34	2,687,492.21	6,494,156.25	9,181,648.46
Aug-24	-	42,053,708.98	-	9,181,648.46	51,235,357.44	1.80%	4.35%	6.15%	76,853.04	185,728.17	262,581.21	2,764,345.25	6,679,884.42	9,444,229.67
Sep-24	-	42,053,708.98	-	9,444,229.67	51,497,938.65	1.80%	4.35%	6.15%	77,246.91	186,680.03	263,926.94	2,841,592.16	6,866,564.45	9,708,156.61
Oct-24	-	42,053,708.98	-	9,708,156.61	51,761,865.59	1.80%	4.35%	6.15%	77,642.80	187,636.76	265,279.56	2,919,234.96	7,054,201.21	9,973,436.17
Nov-24	-	42,053,708.98	-	9,973,436.17	52,027,145.15	1.80%	4.35%	6.15%	78,040.72	188,598.40	266,639.12	2,997,275.68	7,242,799.61	10,240,075.29
Dec-24	-	42,053,708.98	-	10,240,075.29	52,293,784.27	1.80%	4.35%	6.15%	78,440.68	189,564.97	268,005.65	3,075,716.36	7,432,364.58	10,508,080.94
Jan-25	-	42,053,708.98	-	10,508,080.94	52,561,789.92	1.80%	4.35%	6.15%	78,842.68	190,536.49	269,379.17	3,154,559.04	7,622,901.07	10,777,460.11
Feb-25	-	42,053,708.98	-	10,777,460.11	52,831,169.09	1.80%	4.35%	6.15%	79,246.75	191,512.99	270,759.74	3,233,805.79	7,814,414.06	11,048,219.85
Mar-25	-	42,053,708.98	-	11,048,219.85	53,101,928.83	1.80%	4.35%	6.15%	79,652.89	192,494.49	272,147.38	3,313,458.68	8,006,908.55	11,320,367.23
Apr-25	-	42,053,708.98	-	11,320,367.23	53,374,076.21	1.80%	4.35%	6.15%	80,061.11	193,481.03	273,542.14	3,393,519.79	8,200,389.58	11,593,909.37
May-25	-	42,053,708.98	-	11,593,909.37	53,647,618.35	1.80%	4.35%	6.15%	80,471.43	194,472.62	274,944.05	3,473,991.22	8,394,862.20	11,868,853.42
Jun-25	-	42,053,708.98	-	11,868,853.42	53,922,562.40	1.80%	4.35%	6.15%	80,883.84	195,469.29	276,353.13	3,554,875.06	8,590,331.49	12,145,206.55
Jul-25	-	42,053,708.98	-	12,145,206.55	54,198,915.53	1.80%	4.35%	6.15%	81,298.37	196,471.07	277,769.44	3,636,173.43	8,786,802.56	12,422,975.99
Aug-25	-	42,053,708.98	-	12,422,975.99	54,476,684.97	1.80%	4.35%	6.15%	81,715.03	197,477.98	279,193.01	3,717,888.46	8,984,280.54	12,702,169.00
Sep-25	-	42,053,708.98	-	12,702,169.00	54,755,877.98	1.80%	4.35%	6.15%	82,133.82	198,490.06	280,623.88	3,800,022.28	9,182,770.60	12,982,792.88
Oct-25	-	42,053,708.98	-	12,982,792.88	55,036,501.86	1.80%	4.35%	6.15%	82,554.75	199,507.32	282,062.07	3,882,577.03	9,382,277.92	13,264,854.95
Nov-25	-	42,053,708.98	-	13,264,854.95	55,318,563.93	1.80%	4.35%	6.15%	82,977.85	200,529.79	283,507.64	3,965,554.88	9,582,807.71	13,548,362.59
Dec-25	-	42,053,708.98	-	13,548,362.59	55,602,071.57	1.80%	4.35%	6.15%	83,403.11	201,557.51	284,960.62	4,048,957.99	9,784,365.22	13,833,323.21
	$ 42,053,708.98													

1/ 2019 rates per Petitioner's Exhibit 4-G (DLD), Schedule CS1.
2019 rates per Petitioner's Exhibit 4-L (DLD), Schedule CS1.
2020 (and forward) rates per Petitioner's Exhibit 4-G (DLD), Schedule CS3.

EXHIBIT ____ (LK-13)

OUCC
IURC Cause No. 45253
Data Request Set No. 29
Received: September 23, 2019

OUCC 29.2

Request:

Provide the amount of Customer Connect O&M expense by expense account included in operating income, if any. Identify the schedule(s)/workpaper(s) and line item(s) and the amounts where the expenses are included.

Response:

There is no Customer Connect O&M expense included in the forecast test period. The Company is requesting to defer these amounts with carrying costs for recovery in a future rate case.

Witness: Christa L. Graft

EXHIBIT ____ (LK-14)

OUCC
IURC Cause No. 45253
Data Request Set No. 31
Received: September 27, 2019

OUCC 31.1

Request:

Refer to the Direct Testimony of Jeffrey Setser at 27-28, which describes the Company's request for deferral and amortization of pension settlement accounting.

a) Provide the forecast accelerated pension settlement accounting expense and the related deferrals for 2019, the regulatory asset included in rate base at December 31, 2019, and the regulatory asset at December 31, 2020.
b) Provide the forecast accelerated pension settlement accounting expense and the related expense deferrals for 2020, and the regulatory asset included in rate base at December 31, 2020.
c) Provide the amortization expense for the 2019 deferral included in the test year revenue requirement. Indicate if this amortization expense is separately included in the Company's revenue requirement or if it subsumed and included in pension expense included in the revenue requirement.
d) Provide the amortization expense for the 2020 deferral included in the test year revenue requirement. Indicate if this amortization expense is separately included in the Company's revenue requirement or if it subsumed and included in pension expense included in the revenue requirement.

Response:

a) The actuarial study used for forecasting pension-related items for the rate case did not include a forecasted amount for pension settlement expense and related deferrals. Answering further, the Company also did not request rate base treatment for the pension settlement deferral accounting it requested.

   However, in the spirit of cooperation, based on more recent information received from the actuaries since the rate case was prepared, Duke Energy Indiana currently forecasts it will incur pension settlement expense as shown in the following table:

Actual Settlement Charge - June 30, 2019	$	2,685,286
Forecasted Settllement Charges - (Q3/Q4 2019)		1,790,314
Total Settlement Charges - 2019		4,475,599
Less: Amortization expense (2019)		(137,707)
Unamortized Settlement Charges - 12/31/2019	$	4,337,892
Less: Amortization expense (2020)		(459,036)
Unamortized Settlement Charges - 12/31/2020	$	3,878,857

b) See the response to a. There are no additional settlement accounting expense deferrals forecasted for 2020 at the current time.

c) As explained in part a., the actuarial study used for forecasting pension-related items for the rate case did not include a forecasted amount for pension settlement expense and related deferrals. Therefore it did not include any amortization of deferred pension expense in the proposed revenue requirements. It would have included $459,036 in additional pension expense based on the updated forecast that has since been received, as discussed in part a.

d) See the response to parts b. and c.

Witness: Jeffrey R. Setser (latest forecast) / Diana L. Douglas (amounts included in rate case)

EXHIBIT ____ (LK-15)

OUCC
IURC Cause No. 45253
Data Request Set No. 31
Received: September 27, 2019

OUCC 31.2

Request:

Refer to MSFR Workpaper REV1-DLD columns entitled "2020 Forecast" and "Remove Change in Unbilled Revenues."

a. Provide the unbilled revenues at December 31, 2019 and at the end of each month thereafter through the end of the test year in total and separated into base revenues and each of the Company's rider revenues.

b. Provide the calculation of the amounts in the 2020 Forecast column that are removed through proforma adjustments in the Remove Change in Unbilled Revenues column, i.e., show the reversal of the prior month unbilled revenues accrual and the current month accrual for each month in the test year.

c. Confirm that the actual changes in unbilled revenues in the test year will be recorded as revenues on the Company's books in the test year. If this is an incorrect statement, then explain why it is incorrect and provide a corrected statement.

Objection:

Duke Energy Indiana objects to this request to the extent it requires a calculation or compilation not maintained in the normal course of business and that it has not performed and which it objects to performing.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. See Attachment OUCC 31.2-A. Excel spreadsheet Rows 71-112 show the unbilled revenue balances by base rates and rider (as maintained in the forecast model) by month for 2019 and 2020.

b. See Attachment OUCC 31.2-A. Excel spreadsheet Rows 155-181 show the change in unbilled revenues by base rate and rider (as maintained in the forecast model) by month for 2019 and 2020. The monthly change in unbilled is equal to the current month unbilled revenue balance minus the prior month unbilled balance.

c. Yes, the actual changes in unbilled revenues in the test year will be recorded as revenues on the Company's books in the test year.

Witness: Christopher M. Jacobi (a. and b.) / Diana L. Douglas (c.)

EXHIBIT ____ (LK-16)

OUCC
IURC Cause No. 45253
Data Request Set No. 31
Received: September 27, 2019

OUCC 31.10

Request:

Provide a detailed explanation as to why the Company proposes to increase or decrease O&M expense in the test year compared to 2018 for the following accounts. Provide all supporting documentation relied on for the increase in 2020, including descriptions of new regulations, expanded and/or new programs and initiatives,

a. 500
b. 502
c. 511
d. 512
e. 513
f. 514
g. 540
h. 543
i. 544
j. 549
k. 552
l. 553
m. 554
n. 560
o. 561.1, 561.2, 561.3
p. 575.7
q. 587
r. 588
s. 593
t. 594
u. 595
v. 903.

Response:

See Attachment OUCC 31.10-A.

Witness: Christopher M. Jacobi

DUKE ENERGY INDIANA 2019 BASE RATE CASE
OUCC 31-10
O&M variance explanations

Dollars in thousands	**2018A**	**2020E**	**Increase / (Decrease)**	Variance explanation
0500000 - Suprvsn and Engrg - Steam Oper	24,771	31,298	6,527	$4.9M Increase in strategic programs; $1.7M increase for Edwardsport outage
0502020 - Ammonia - Qualifying	5,304	5,670	366	
0502040 - Cost of Lime	19,911	21,803	1,891	Account 0502040 is due to Gibson process BLIMEQ (Lime) and BLMSTNQ (Limestone) related to Unit 4 and Unit 5
0502060 - Soda Ash - Qualifying	10,301	12,702	2,401	Gibson GB05 Reagent Spend & Model. Annual dollar amounts fluctuate based on unit run profile and generation i
0502070 - Gypsum - Qualifying	1	0	(1)	
0502082 - Re-emission Chem Exp - Reagent	1,858	0	(1,858)	Actuals hit 0502082 and budgeted to 0502090 with the process code BREEMNQ
0502084 - Calcium Bromide Exp - Reagent	1,062	479	(582)	
0502090 - Calcium Carbonate	(7)	3,146	3,153	Actuals hit 0502082 and budgeted to 0502090 with the process code BREEMNQ
0502100 - Fossil Steam Exp - Other	24,471	35,567	11,096	Cayuga Coal $2.53M budgeted to process code BMCE (Monitoring/Controlling Equipment - Base) $62K in spend, a
0502410 - Steam Oper-Bottom Ash/Fly Ash FL	2	0	(2)	
502 total	62,903	79,367	16,464	
0511000 - Maint of Structures - Steam	24,599	20,502	(4,098)	
0511200 - Maint Of Structures-Steam - Recoverable	0	0	(0)	
511 total	24,600	20,502	(4,098)	Edwardsport IGCC budget reductions
0512100 - Maint of Boiler Plant - Other	111,355	96,767	(14,588)	
0512300 - Maint Of Boiler Plant-Other - Recoverable	(14,019)	0	14,019	
512 total	97,336	96,767	(569)	Geography between accounts
0513100 - Maint of Electric Plant - Other	17,967	52,059	34,092	Edwardsport ED01 Outage
0514000 - Maintenance - Misc Steam Plant	9,870	16,603	6,733	
0514300 - Maintenance - Misc Steam Plant	5	0	(5)	
514 total	9,875	16,603	6,728	Scrubber waste hauling at Gibson Station charged to ARO Basin Closure project in 2018, Costs transition to O&M c
0540000 - Rents - Hydro Oper	160	658	497	Rent is a FERC Government Dam charge based one year in lag due to generation. Due to major outage in 2018 the
0543000 - Maint - Reservoir Dam and Waterway	474	791	316	Labor resource sharing to uprate Capital projects, lower contract and material spend in 2018, less maintenance du
0544000 - Maint of Electric Plant - Hydro	160	344	184	Related to the uprate projects at Markland, less spend in 2018 than anticipated, this spend will not continue after
0549000 - Misc - Power Generation Expenses	5,147	3,221	(1,926)	Central Services budgeted compliance expense for CT sites across the fleet. Budgeted to account 0512100 insteac
0552000 - Maintenance of Structures - Ct	1,625	3,749	2,124	Noblesville CT 2020 Outage
0553000 - Maint - Gentg and Elect Equip - Ct	4,194	10,850	6,655	
0553100 - CT Maint of Gen and Plant-Recoverable	0	0	(0)	
553 total	4,194	10,850	6,655	Wheatland CT Outage $1.2M; Vermillion CT Outage $800K; Noblesville Ct Outage $3M; Madison CT Outage $500K
0554000 - Misc Power Generation Plant - Ct	2,204	811	(1,393)	
0554220 - Solar: Maint Misc Gen Plt	0	0	(0)	
554 total	2,204	811	(1,393)	CT Fleet reductions/mitigation
0560000 - Supervsn and Engrng - Trans Oper	55	832	776	Miscellaneous office expenses incorrectly budgeted to Account 560 in 2020, correct account is 566. Actuals were (
0561100 - Load Dispatch - Reliability	(666)	1,686	2,352	

DUKE ENERGY INDIANA 2019 BASE RATE CASE
OUCC 31-10
O&M variance explanations

Dollars in thousands	**2018A**	**2020E**	**Increase / (Decrease)**	Variance explanation
0561200 - Load Dispatch - MnitorandOprtrnsys	5,583	2,827	(2,756)	
0561300 - Load Dispatch - TranssvcandSch	769	1,473	703	
561 total	5,687	5,986	299	Charging allocation across 561 accounts updated to represent the work activities currently being performed, offs
0575700 - Market Faciliation - MntrandComp	6,139	8,784	2,645	2020 budget potentially overstated by $2M due to higher than trended budget for MISO Schedule 17
0587000 - Cust Install Exp - Other Dist	4,350	13,062	8,713	$4.6M Meter Reading budgeted to 587 should have been budgeted to 902. $3.7M Customer orders costs hit 586
0588100 - Misc Distribution Exp - Other	17,754	17,489	(265)	
0588300 - Load Mang - Gen and Control - Dist	1,319	519	(799)	
0588301 - Miscellaneous Distribution Exp	3,510	(5,216)	(8,727)	
588 total	22,583	12,792	(9,791)	2018 actuals contains both deferrals and amortizations related to TDSIC recovery. The budget for 2020 only conta
0593000 - Maint Overhd Lines - Other - Dist	50,352	41,808	(8,543)	
0593100 - Right - Of - Way Maintenance - Dist	12,770	38,626	25,855	
593 total	63,122	80,434	17,312	Increase of $14M in Vegetation management; additional $1M associated with project O&M related to system & re
0594000 - Maint - Underground Lines - Dist	2,575	391	(2,184)	A combined underground and overhead outage amount was budgeted in 593 account. Actuals of $1.7M recorded
0595100 - Maint Lines Transfrs - Other - Dist	332	1,180	848	2018 actual environmental costs split between 588 and 595 account; all budgeted to 595
0903000 - Cust Records and Collection Exp	17,997	12,859	(5,138)	
0903100 - Cust Contracts and Orders - Local	858	7,065	6,207	
0903200 - Cust Billing and Acct	4,413	3,964	(450)	
0903300 - Cust Collecting - Local	1,131	2,250	1,119	
0903400 - Cust Receiv and Collect Exp - Edp	236	500	263	
0903891 - IC Collection Agent Revenue	(1,421)	(1,389)	32	
903 total	23,214	25,249	2,034	Increases in postage, labor and contract services

DUKE ENERGY INDIANA 2019 BASE RATE CASE
OUCC 31-10
O&M variance explanations

Dollars in thousands

0500000 - Suprvsn and Engrg - Steam Oper	
0502020 - Ammonia - Qualifying	
0502040 - Cost of Lime	engineering model based on generation.
0502060 - Soda Ash - Qualifying	'orecasted in the model.
0502070 - Gypsum - Qualifying	
0502082 - Re-emission Chem Exp - Reagent	
0502084 - Calcium Bromide Exp - Reagent	
0502090 - Calcium Carbonate	
0502100 - Fossil Steam Exp - Other	ctuals hit various other process codes based on actual workorders charged. Gibson process code BLIME (Lime) $4.4M spend and generation model forecast.
0502410 - Steam Oper-Bottom Ash/Fly Ash FL	
502 total	
0511000 - Maint of Structures - Steam	
0511200 - Maint Of Structures-Steam - Recoverable	
511 total	
0512100 - Maint of Boiler Plant - Other	
0512300 - Maint Of Boiler Plant-Other - Recoverable	
512 total	
0513100 - Maint of Electric Plant - Other	
0514000 - Maintenance - Misc Steam Plant	
0514300 - Maintenance - Misc Steam Plant	
514 total	ınce Basin Closure needs for fill are satisfied and waste is transported to landfill.
0540000 - Rents - Hydro Oper	: fee was much lower, expectation is for generation to levelize.
0543000 - Maint - Reservoir Dam and Waterway	ıe to downtime for uprate projects in 2018 - all related to Markland.
0544000 - Maint of Electric Plant - Hydro	the uprate projects are complete.
0549000 - Misc - Power Generation Expenses	ł of 0549000 which results in the decrease from 2018 actuals to 2020 budget.
0552000 - Maintenance of Structures - Ct	
0553000 - Maint - Gentg and Elect Equip - Ct	
0553100 - CT Maint of Gen and Plant-Recoverable	
553 total	:
0554000 - Misc Power Generation Plant - Ct	
0554220 - Solar: Maint Misc Gen Plt	
554 total	
0560000 - Supervsn and Engrng - Trans Oper	:harged appropriately to Account 566
0561100 - Load Dispatch - Reliability	

DUKE ENERGY INDIANA 2019 BASE RATE CASE
OUCC 31-10
O&M variance explanations

Dollars in thousands

0561200 - Load Dispatch - MnitorandOprtrnsys	
0561300 - Load Dispatch - TranssvcandSch	
561 total	ətting impact to Account 561 in total
0575700 - Market Faciliation - MntrandComp	
0587000 - Cust Install Exp - Other Dist	account in 2018 actuals.
0588100 - Misc Distribution Exp - Other	
0588300 - Load Mang - Gen and Control - Dist	
0588301 - Miscellaneous Distribution Exp	
588 total	ıins a deferral of costs for future recovery, and assumes no amortization of costs from previous years is necessary.
0593000 - Maint Overhd Lines - Other - Dist	
0593100 - Right - Of - Way Maintenance - Dist	
593 total	ɜtail capacity capital; remaining variance primarily due to underground and overhead budget is all in 593, but actuals split between 593 and 594
0594000 - Maint - Underground Lines - Dist	in 594 account for 2018 actuals.
0595100 - Maint Lines Transfrs - Other - Dist	
0903000 - Cust Records and Collection Exp	
0903100 - Cust Contracts and Orders - Local	
0903200 - Cust Billing and Acct	
0903300 - Cust Collecting - Local	
0903400 - Cust Receiv and Collect Exp - Edp	
0903891 - IC Collection Agent Revenue	
903 total	

EXHIBIT ____ (LK-17)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's Second Set Data Requests
Date Received: November 29, 2017

AG-DR-02-027

REQUEST:

Refer to the Duke Energy Business Services, Inc. ("DEBS") 2016 FERC Form 60 at pages 201, 301, and 302.

a. Refer to the amount of net income after taxes reflected on page 302 at line 62 and the amount of income taxes on page 302 at lines 42-44. Explain how the service company reflected net income of approximately \$26.9 million after net income tax expense of approximately \$20.9 million in 2016 and net income of approximately \$21.3 million after net income tax expense of approximately \$18.3 million in 2015 as opposed to net income and income taxes at around zero if all costs were charged to affiliates at cost.

b. Refer to page 201 at lines 14 and 15. The balance of Unappropriated Retained Earnings at the end of 2016 was approximately \$421.9 million and dividends paid during 2016 were approximately \$5.9 million. Confirm that the amount of Unappropriated Retained Earnings represents profits retained at DEBS, after annual dividends to stockholders, and that those profits represent billings to affiliates in excess of actual costs on a cumulative basis.

c. Are any costs charged to affiliates, such as DEK, based on an equity return on investment component as opposed to just the return of component and interest charges? If so, explain and describe the basis for the equity return added to costs charged to affiliates as well as the actual return on equity percentage added during 2016 and the projected return on equity percentage for the test year.

d. Provide a schedule showing the monthly forecasted net income for DEBS, before and after income taxes, for each month during 2018 and the first three months of 2019.

e. Provide a schedule showing the monthly forecasted recovery of equity return for DEBS, including income taxes, charged to DEK, including charges directly to DEK from DEBS and all charges from other affiliates that include charges from DEBS. Provide all calculations, including electronic spreadsheets in live format with all formulas intact.

RESPONSE:

a. The Service Company charges a return for the use of DEBS assets to the jurisdictions. This represents a cost of capital for assets on the Service Company that are used in the operations of Duke Energy and its subsidiary companies. For 2016 the return on DEBS assets was $47.86 million, income tax expense was $20.94, resulting in net income of $26.9 million. For 2015 the return on DEBS assets was $39.71, income tax expense was $18.45, resulting in net income of $21.3 million. The income statement for

DEBS would have been close to zero, except for the return on assets and income tax expense.

b. The amount of Unappropriated Retained Earnings does represent billings in excess of costs recorded on DEBS ledger on a cumulative basis. The nature of these billings in excess of costs can be categorized into two categories. Prior to the Duke Cinergy merger, which brought Kentucky under Duke Energy Corporation, the legacy Duke Corporation utilized a tax strategy in which the Service Company charged a management fee for services provided. The cost to the utilities, primarily Duke Energy Carolinas, was recorded to a below the line non-utility account. The reorganization associated with the Duke Cinergy merger negated this strategy going forward. The second category is the return on DEBS assets. The Service Company to Utility Service Agreement states that the company shall cover all costs of doing business. Cost as defined in the agreement means "fully embedded costs, namely, the sum of (1) direct costs, (2) indirect costs and (3) **costs of capital**." The return on DEBS assets is a charge to recover the cost of capital to the utilities for the use of these assets.

c. A return on DEBS assets is recorded based on a monthly calculation of DEBS assets. These assets include PP&E, prepaid pension assets and inventory. The PP&E is determined based on NET PP&E less CWIP less associated deferred taxes. Prepaid pension assets are determined by taking the prepaid qualified pension, less the non-qualified pension and OPEB liabilities and decreasing by a deferred tax amount. The inventory amount is the amount reflected on the inventory balance sheet for DEBS. The total allocated amount of assets assigned to the Regulated Utility is multiplied by a revenue requirement percentage to achieve the allowed rate of return in the jurisdiction. The amount allocated to the utility is based on a 3 factor allocation for PP&E and inventory assets. The pension assets are allocated based on DEBS labor usage. This process is applicable to 2016, 2017 and for the projected test year. The revenue requirement percentage used for Kentucky is based on the 2006 Kentucky Electric rate case for all actual and forecasted periods. Please see AG-DR-02-027(c) Attachment being uploaded electronically and a copy provided on CD.

d. See table below:

$000s	Before taxes	After taxes
Jan-18	5,077	3,071
Feb-18	5,077	3,071
Mar-18	5,077	3,071
Apr-18	5,077	3,071
May-18	5,077	3,071
Jun-18	5,077	3,071
Jul-18	5,077	3,071
Aug-18	5,077	3,071
Sep-18	5,077	3,071
Oct-18	5,077	3,071

Nov-18	5,077	3,071
Dec-18	5,077	3,071
Jan-19	5,125	3,102
Feb-19	5,125	3,102
Mar-19	5,125	3,102

e. Please see AG-DR-02-027(e) Attachment being uploaded electronically and a copy provided on CD. This file includes multiple worksheets. The first worksheet "DEK Return" shows the monthly values for the forecasted test period for each of the components of the return as well as the total and tax effects. The following 3 worksheets for both 2018 and 2019 are the worksheets used to calculate the monthly values. Each worksheet shows the detailed calculations for the DEK electric component of the DEBS return that are linked to the "DEK Return" worksheet.

PERSON RESPONSIBLE: Jeff Setser (a-c, e)
Beau Pratt (d)

EXHIBIT ____ (LK-18)

OUCC
IURC Cause No. 45253
Data Request Set No. 20
Received: September 6, 2019

OUCC 20.6

Request:

Describe how DEBS treated the EDIT resulting from the lower federal income tax rate due to the TCJA. Provide the DEBS accounting entries.

Response:

DEBS remeasured its ADIT based on the new federal corporate income tax rate of 21% and removed the excess ADIT through the income statement.

BU 20011: Duke Energy Corporate Services, Inc.
BU 20013: Duke Energy Business Services, LLC

BU	Account	Amount
20011	0282100	(1,400,278)
20011	0410240	1,400,835
20011	0411240	(557)
20013	0190001	(78,967,867.76)
20013	0282100	39,476,466.38
20013	0283100	64,020,350.07
20013	0410240	157,689,441.25
20013	0411240	(182,218,389.94)
20013	0190051	(2,803,931.00)
20013	0410240	2,803,931.00

Witness: John Panizza

EXHIBIT ____ (LK-19)

OUCC
IURC Cause No. 45253
Data Request Set No. 20
Received: September 6, 2019

OUCC 20.5

Request:

Provide a schedule showing the EDIT by temporary difference for DEBS (total DEBS and allocation to DEI) due to the remeasurement of ADIT resulting from the lower federal income tax rate due to the TCJA. If there was no allocation to DEI, then provide the DEBS allocation factor used to allocate/charge depreciation expense on DEBS assets to DEI.

Response:

There was not an allocation of DEBS EDIT to Duke Energy Indiana. The DEBS allocation factor used to allocate/charge depreciation expense on DEBS asset to Duke Energy Indiana is 10.48%.

Witness: John Panizza

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

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